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Millstone Power Station
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Dominion

December 3, 2004

United States Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, DC 20555-0001

Serial No.: 04-720
LR/ELA R0
Docket Nos.: 50-336
50-423
License Nos.: DPR-65
NPF-49

DOMINION NUCLEAR CONNECTICUT, INC. (DNC)
MILLSTONE POWER STATION UNITS 2 AND 3
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION
LICENSE RENEWAL APPLICATIONS

The Nuclear Regulatory Commission (NRC) requested additional information regarding the license renewal applications (LRAs) for Millstone Power Station Units 2 and 3 on June 25, 2004, June 26, 2004, August 10, 2004, August 16, 2004, September 23, 2004, and October 14, 2004. The response to these requests is being submitted as Attachment 1. Supplemental information was also requested by the staff regarding a responses previously provided by letters dated July 26, 2004 (S/N: 04-405) and November 9, 2004 (S/N: 04-673). The supplemented responses are included as Attachment 2.

As a result of audits of the Aging Management Programs and Aging Management Reviews conducted November 15-16, 2004, additional information in support of the Millstone Power Station Units 2 and 3 LRAs is being submitted as Attachment 3.

Should you have any questions regarding this letter, please contact Mr. William D. Corbin, Director, Nuclear Projects, Dominion Resources Services, Inc., at (804) 273-2365.

Very truly yours,

Leslie N. Hartz
Vice President – Nuclear Engineering

A106

Attachments:

1. Request for Additional Information Responses
2. Supplemental Request for Additional Information Response
3. Additional Information in Support of Applications for Renewed Operating Licenses

Commitments made in this letter:

This letter identifies various License Renewal Commitments to be added to Table A6.0-1 of the Final Safety Analysis Report (FSAR) Supplement and are proposed to support approval of the renewed operating licenses. These commitments may change during the NRC review period. A revised FSAR Supplement which contains these commitments will be submitted to the staff as input to the Millstone License Renewal Safety Evaluation Report.

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SN: 04-720
Docket Nos.: 50-336/423
Subject: Response to RAI Regarding License Renewal

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Leslie N. Hartz, who is Vice President - Nuclear Engineering, of Dominion Nuclear Connecticut, Inc. She has affirmed before me that she is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of her knowledge and belief.

Acknowledged before me this 3rd day of December, 2004.

My Commission Expires: May 31, 2006.

Vicki L. Hull
Notary Public

(SEAL)

Attachment 1

Request for Additional Information Responses

Millstone Power Station Units 2 & 3
Dominion Nuclear Connecticut, Inc.

RAI 2.4-1

(Part 1)

Tables 2.2-4 in the Millstone 2 and Millstone 3 LRAs list the structures that are not in the scope of license renewal. For most of the structures listed, there is no descriptive information in the FSARs. Consequently, the staff could not determine whether all of the structures listed in LRA Table 2.2-4 would meet any of the criteria in 10 CFR 54.4 (a) (1-3). For each of the following structures not described in the FSARs, the applicant is requested to provide a description of these structures including their associated functions:

- 6000 Gal. Above Ground Fuel Tank Foundation
- Above Ground Diesel Fuel Tank Foundation
- Above Ground Gasoline Tank Foundation
- A-Frame
- Block House (Electric)
- Chemistry Safety Storage Building
- Condensate Polishing Service Water Strainer House (Unit 2)
- Flammable Liquids/ Hazardous Material Building
- Flammable Storage Buildings
- Fuel Oil Storage Facility
- Gas Bottle Storage Building
- Hazardous Waste Processing
- Hazardous Waste Storage Bldg.
- Hydrogen Recombiner Portable PCM Enclosure
- Incompatible Hazardous Waste Storage Bldg.
- Low Level Radwaste Storage
- MRRF PCM Enclosure
- Steel Transmission Towers
- Unit 1 Discharge Structure
- Unit 1 Intake Structure
- Unit 1 Reactor Building
- Unit 1 Solid Radwaste Building
- Unit 1 Switchyard
- Unit 1 Waste Surge Tank Foundation
- Unit 1 Xenon-Krypton Building
- Unit 2 Hydrogen Cylinder Storage Area
- Unit 2 Service Water Pump Strainer House Structure
- Unit 3 Auxiliary Building PCM Enclosure
- Unit 3 Condensate Surge Tank Foundation

- Unit 3 Domestic Water Storage Tank Foundation
- Unit 3 Groundwater Underdrains Storage Tank Foundation
- Unit 3 PGST A and B Nitrogen Storage Tank Foundation
- Unit 3 Water Treatment Storage Tank Foundation

(Part 2)

In addition, the applicant is requested to verify that a seismic II/I intended function, in accordance with 10 CFR 54.4(a)(2), is not applicable to any of the structures and structural components listed in LRA Table 2.2-4.

Dominion Response:

(Part 1)

6000 Gal. Above Ground Fuel Tank Foundation (bldg 484)

The foundation for this tank is the concrete loading dock. This is a freestanding modular tank structure that is located on top of the concrete loading dock between buildings 409 and 410. The tank does not have a foundation designed specifically for the tank. The tank stores heating fuel oil for the heating systems in these buildings. Neither these buildings nor the loading dock or the tank has a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Above Ground Diesel Fuel Tank Foundation (bldg 476)

This is a concrete foundation that provides structural support for the tank that is used to store diesel fuel oil for the motor pool. Neither the foundation nor the tank has a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Above Ground Gasoline Tank Foundation (bldg 474)

This is a concrete foundation that provides structural support for the tank that is used to store gasoline for the motor pool. Neither the foundation nor the tank has a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

A-Frame (bldg 503)

This is a freestanding structure outside the protected area that is used for meetings and administrative functions. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Block House (Electric) (bldg 423)

This is a freestanding structure that houses electrical equipment for the non-safety related off-site power supply. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Chemistry Safety Storage Building (bldg 457)

This is a freestanding modular structure that is used for temporary storage of flammable or hazardous materials. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Condensate Polishing Service Water Strainer House (Unit 2) (bldg 222)

This is the same structure as the "Unit 2 Service Water Pump Strainer House Structure" listed below. This Class II structure is located adjacent to and north of the Unit 2 Intake Structure and originally housed the strainer for the service water supply to the condensate polishing facility. The service water supply is no longer required, the strainer has been removed, and the associated piping is capped and abandoned. The building is currently used by the Maintenance Department for storage of maintenance equipment. It does not contain any equipment that is in scope of license renewal. The Unit 2 Intake Structure, which is a safety related Class I structure, is in the scope of license renewal.

The Condensate Polishing Service Water Strainer House is a heavily reinforced concrete structure with 12-inch-thick walls and an 8-inch reinforced concrete roof slab that supports a built-up roofing system. The Condensate Polishing Service Water Strainer House is separated from the Intake Structure by a seismic gap filled with compressible material. This compressible material is in the scope of license renewal and subject to aging management. It is included in the Commodity Group "Expansion joint/Seismic gap material (between adjacent buildings/structures)", as indicated in LRA Table 2.4.2-25, Miscellaneous Structural Commodities.

FSAR Section 5.1.1.1 Class I Structures states that "Class I structures are designed to withstand the appropriate seismic and other applicable loads without loss of function. These Class I structures are sufficiently isolated or protected from Class II structures to ensure that their integrities are maintained at all times."

Based on the statements from FSAR Section 5.1.1.1 and on the robust design and construction of the Condensate Polishing Service Water Strainer House including the seismic gap, it is not credible to postulate failure of this structure. Even if such failure is postulated, it will not prevent the Class I Intake Structure from performing its intended function. However, to conservatively ensure the integrity of the Class 1 Intake Structure, the Condensate Polishing Service Water Strainer House will be added to the scope of license renewal. The structure consists of structural reinforced concrete in air and

atmosphere/weather environment. The aging effects requiring management are loss of material, cracking, and change of material properties. These aging effects will be managed by the Structures Monitoring Program AMP that is described in LRA Section B2.1.23. The aging management review results are included in Table 1.

Flammable Liquids/ Hazardous Material Building (bldg 479)

This is a freestanding modular structure that is used for temporary storage of flammable or hazardous materials. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Flammable Storage Buildings (bldgs 421, 477, 481)

These are freestanding structures that are used for temporary storage of flammable materials. None has a license renewal intended function. These non-safety related structures are located such that they do not affect any safety related structures.

Fuel Oil Storage Facility (bldg 128)

This is a freestanding structure that was under construction when it was abandoned in place. It was never completed and does not store any fuel oil. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Gas Bottle Storage Building (bldg 450)

This is a freestanding structure that is used for storage of bottled gas. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Hazardous Waste Processing (bldg 455)

This is a freestanding structure that is used for processing hazardous waste. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Hazardous Waste Storage Bldg. (bldg 543)

This is a freestanding structure outside the protected area that is used for temporary storage of hazardous waste materials. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Hydrogen Recombiner Portable PCM Enclosure (bldg 657)

This enclosure housed the personnel contamination monitors (PCM) used for monitoring personnel contamination when exiting the radiologically controlled area of the hydrogen recombiner building. This enclosure has been removed from the south side of the hydrogen recombiner building.

Incompatible Hazardous Waste Storage Bldg. (bldg 544)

This is a freestanding structure outside the protected area that is used for temporary storage of incompatible hazardous waste materials. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Low Level Radwaste Storage (bldg 505)

This is a freestanding structure outside the protected area that is used for temporary storage of low-level radwaste materials. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

MRRF PCM Enclosure (bldg 461)

This is a freestanding structure that houses the personnel contamination monitors (PCM) used for monitoring personnel contamination when exiting radiologically controlled area at the Millstone Radwaste Reduction Facility (MRRF). It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Steel Transmission Towers

These are freestanding steel towers mounted on concrete foundations. The steel transmission towers and their foundations are generally not in the scope of license renewal with one exception. The three steel transmission towers and foundations required to support the electrical lines for Station Blackout as required by 10CFR54.4(a)(3) are in the scope of license renewal. These towers are identified as being in the scope of license renewal in section 2.4.2.25 of the Unit 3 LRA and section 2.4.2.16 of the Unit 2 LRA. The remaining steel towers are those referenced in Table 2.2-4.

Of the three towers that are in scope, one tower supports the 345kV lines between the Unit 3 reserve station service transformer and the switchyard and the other two support the 345kV lines between the Unit 2 reserve station service transformer and the switchyard as shown on license renewal Site Plan 25205-LR10025.

The height of Steel Transmission Towers varies from 85 to 115 feet as indicated in the table below:

Tower No.	Height (ft)	Unit	In-scope of LR
1T-1	100	1	N
1T-2	115	1	N
1T-3	115	1	N
1G-1	105	1	N
1G-2	105	1	N
1G-3	110	1	N
2T-2	85	2	Y
2T-3	90	2	Y
2G-2	85	2	N
2G-3	90	2	N
3G-2	85	3	N
3G-3	110	3	N
3T-3	110	3	Y

All steel transmission towers are located far enough away from the plant so that if any were to fall, they would not cause any damage to any in scope structure/component that performs a safety related function.

The steel transmission tower not in scope of license renewal that is closest to a safety related structure/component is tower number 3G-2. The safety related structure is the Unit 3 Refueling Water Storage Tank (bldg 313). This tower is 85 feet tall and is located approximately 160 feet to the east of the Refueling Water Storage Tank. All the remaining steel transmission towers that are not in scope of License Renewal are more than 360 feet away from any safety related structure/component.

Unit 1 Discharge Structure (bldg 102)

This is a reinforced concrete embedment type structure that terminates the Unit 1 condenser discharge piping where it enters the common discharge quarry. It is part of the permanently defueled boiling water reactor nuclear power complex located at the southern end of the site. It does not have a license renewal intended function. This Unit 1 non-safety related structure is located such that it does not affect any Unit 2 or Unit 3 safety related structures.

Unit 1 Intake Structure (bldg 107)

This is a freestanding reinforced concrete structure that houses the cooling water pumps that used to supply the Unit 1 condenser and service water systems. It is part of the permanently defueled boiling water reactor nuclear power complex located at the southern end of the Millstone site. It does not have a license renewal intended function. This Unit 1

non-safety related structure is located such that it does not affect any Unit 2 or Unit 3 safety related structures.

Unit 1 Reactor Building (bldg 111)

This is a reinforced concrete structure that houses the remnants of the Unit 1 nuclear reactor, and the spent fuel pool. It is part of the permanently defueled boiling water reactor nuclear power complex located at the southern end of the Millstone site. It does not have a license renewal intended function. The Unit 1 Reactor Building structure is being maintained as safety related class 1 for Unit 1 decommissioning purposes only. Therefore, it does not affect any Unit 2 or Unit 3 safety related structures.

Unit 1 Solid Radwaste Building (bldg 119)

This is a concrete and steel structure that provides an area for indoor storage of solid radwaste for the Unit 1 radwaste processing systems. It is part of the permanently defueled boiling water reactor nuclear power complex located at the southern end of the Millstone site. It does not have a license renewal intended function. This Unit 1 non-safety related structure is located such that it does not affect any Unit 2 or Unit 3 safety related structures.

Unit 1 Switchyard (bldg 104)

This is a series of steel structures that supports the transmission equipment for the electrical power previously generated at Unit 1. It is part of the permanently defueled boiling water reactor nuclear power complex located at the southern end of the Millstone site. It does not have a license renewal intended function. This Unit 1 non-safety related structure is located such that it does not affect any Unit 2 or Unit 3 safety related structures.

Unit 1 Waste Surge Tank Foundation (bldg 115)

This is a concrete foundation that provides structural support for the waste surge tank. It is part of the permanently defueled boiling water reactor nuclear power complex located at the southern end of the Millstone site. It does not have a license renewal intended function. This Unit 1 non-safety related structure is located such that it does not affect any Unit 2 or Unit 3 safety related structures.

Unit 1 Xenon-Krypton Building (bldg 116)

This is a freestanding concrete structure that houses the charcoal absorption beds previously used to process effluent gases from Unit 1. It is part of the permanently defueled boiling water reactor nuclear power complex located at the southern end of the Millstone site. It does not have a license renewal intended function. This Unit 1 non-safety related structure is located such that it does not affect any Unit 2 or Unit 3 safety related structures.

Unit 2 Hydrogen Cylinder Storage Area (bldg 226)

This is a freestanding multi-tank structure that is used for storage and supply of hydrogen used at Unit 2. The structure consists of a concrete slab foundation on grade that supports a masonry block wall on two sides. Upon further review, the masonry block wall has been determined to function as a firewall between the storage facility and the Unit 2 Turbine Building and should have been identified with a fire barrier function. As a result, this structure has been added to the scope of license renewal.

The structural members consist of structural reinforced concrete in soil and atmosphere/weather environments and masonry block walls in an atmosphere/weather environment. The aging effects requiring aging management are change of material properties, cracking, and loss of material for the structural reinforced concrete and cracking for the masonry block walls. These aging effects will be managed during the period of extended operation by the Structures Monitoring Program AMP that is described in LRA Section B2.1.23. The aging management review results are included in Table 2.

Unit 2 Service Water Pump Strainer House Structure (bldg 222)

This is the same structure as the "Condensate Polishing Service Water Strainer House (Unit 2)" listed above.

Unit 3 Auxiliary Building PCM Enclosure (bldg 463)

This is a wooden structure that houses the personnel contamination monitors (PCM) used for monitoring personnel contamination when exiting the radiologically controlled areas within the buildings of the Unit 3 nuclear power complex. It does not have a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Unit 3 Condensate Surge Tank Foundation (bldg 304)

This is a concrete foundation that provides structural support for the condensate surge tank. Neither the foundation nor the tank has a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

Unit 3 Domestic Water Storage Tank Foundation

This item was listed in error. Unit 3 does not have a tank (or foundation) with this name. Unit 3 does have a water treatment storage tank that contains domestic water. The Water Treatment Storage Tank and its foundation are not in the scope of license renewal. This non-safety related structure is located such that it does not affect any safety related structures.

Unit 3 Groundwater Underdrains Storage Tank Foundation

This tank shares the concrete foundation of the refueling water storage tank (bldg 313). Note that the LRA Table 2.2-4 inadvertently listed a structure "Unit 3 Groundwater Underdrains Storage Tank Foundation" although there is no such structure at Millstone Power Station. The refueling water storage tank and its foundation are in scope of license renewal. In addition, the groundwater underdrains storage tank was added to the scope of license renewal during the 10CFR54.4(a)(2) review (reference RAI 2.1-1). Therefore, both tanks and the common foundation are in the scope of license renewal.

Unit 3 PGST A and B Nitrogen Storage Tank Foundation

This is a concrete foundation that provides structural support for the A & B primary grade water storage tanks nitrogen system tank. It is located adjacent to the primary grade water storage tanks foundation. Neither this tank nor its foundation has a license renewal intended function. These non-safety related structures are located such that they do not affect any safety related structures.

Unit 3 Water Treatment Storage Tank Foundation (bldg 306)

This is a concrete foundation that provides structural support for the water treatment storage tank. Neither this tank nor its foundation has a license renewal intended function. This non-safety related structure is located such that it does not affect any safety related structures.

(Part 2)

With regard to verification of the applicability of the seismic II/I intended function for all the structures or structural components in LRA Table 2.2-4, the scoping process, outlined in Section 2.1.4.1, required review of the seismic II/I intended function of all of the structures. The structures reviewed above provide another verification through a sampling of the process and indicate that the scoping methodology is consistent with the requirements in 10CFR54.4.

Table 1: Unit 2 Condensate Polishing Service Water Strainer House

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Structural Reinforced Concrete	SNS	Concrete	(E) Air	Change of Material Properties	Structures Monitoring Program			H
				Cracking	Structures Monitoring Program	III.A6.1-c	3.5.1-22	A
			(E) Atmosphere/Weather	Change of Material Properties	Structures Monitoring Program			H
				Cracking	Structures Monitoring Program	III.A6.1-a	3.5.1-22	A
					Structures Monitoring Program	III.A6.1-c	3.5.1-22	A
				Loss of Material	Structures Monitoring Program	III.A6.1-a	3.5.1-22	A

Table 2: Unit 2 Hydrogen Cylinder Storage Area

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Masonry block walls	FB	Concrete	(E) Atmosphere/Weather	Cracking	Structures Monitoring Program			G
Structural Reinforced Concrete	SNS	Concrete	(E) Atmosphere/Weather	Change of Material Properties	Structures Monitoring Program			H
				Cracking	Structures Monitoring Program	III.A8.1-c	3.5.1-20	A
					Structures Monitoring Program	III.A8.1-a	3.5.1-20	A
				Loss of Material	Structures Monitoring Program	III.A8.1-a	3.5.1-20	A
			(E) Soil	Change of Material Properties	Structures Monitoring Program	III.A8.1-e	3.5.1-21	A
				Cracking	Structures Monitoring Program	III.A8.1-e	3.5.1-21	A
					Structures Monitoring Program	III.A8.1-d	3.5.1-21	A
				Loss of Material	Structures Monitoring Program	III.A8.1-e	3.5.1-21	A
					Structures Monitoring Program	III.A8.1-d	3.5.1-21	A

RAI 2.4-2

Based on review of the FSAR sections referenced in LRA Table 2.2-4, and additional related sections of the FSAR, the staff could not conclude that all of the structures described in the FSAR sections serve no intended function. The applicant is requested to provide additional information, as indicated below, for the following structures that are described in the FSARs:

- Part 1

The Unit 2 and 3 Main and Normal Station Transformers are described in Unit 2 FSAR Section 8.1.1, Unit 3 FSAR Section 8.1.7, and Unit 3 FSAR Section 8.3.1.1.1. In Unit 3 FSAR Section 8.3.1.1.1, it states "The normal station service transformers have the capacity to supply normal auxiliaries and those emergency auxiliaries (both load groups) required during normal operation up to the full output of the main generator plus the capacity to supply Millstone Unit 2 GDC 17 requirements as an alternate offsite source for minimum post accident loads." and "Power is supplied to the normal 6.9 kV and 4.16 kV buses through four stepdown transformers, of which two are normal station service transformers and two are reserve station service transformers. Each transformer is fully rated to carry all the loads on its buses during normal operation and any postulated design basis accident plus to carry Millstone Unit 2 minimum post-accident loads to satisfy GDC 17 requirements as a Unit 2 alternate offsite source."

In Unit 3 FSAR Section 3.1.2.5 "Sharing of Structures, Systems, and Components (Criterion 5)", it states the following equipment may be shared and utilized by Millstone Unit 2 to meet its GDC 17 requirements for an alternate offsite source to relieve one of its emergency diesel generators and supply power to minimum post accident loads:

1. Main Transformers 15G 3X A and 15G 3X B
2. Normal Station Service Transformer 15G 3SA
3. Reserve Station Service Transformer 15G 23SA

The sharing of this equipment does not impair its ability to perform its safety function. The transformers are adequately sized and have sufficient capacity to meet maximum postulated Unit 3 loading requirements while supplying Unit 2 GDC 17 minimum loads.

Based on this FSAR information, it appears to the staff that some of these transformers perform an intended function; if so, then the transformers' structural support would also perform an intended function. The applicant is requested to clarify whether any of these transformers and their structural supports perform an intended function and need to be included in the scope of license renewal.

- Part 2

"Miscellaneous Warehouses (#9, #8, #3, #4, #5, #6)" is listed in LRA Table 2.2-4 as out-of-scope. The FSAR Reference is Unit 3 FSAR Section 3.1.2.5 and FPER 5.5 Analysis 76. The staff notes that LRA Tables 2.2-3 for both Unit 2 and Unit 3 list the "Unit 2 Condensate Polishing Facility and Warehouse No. 5" as being within the scope of license renewal. The applicant is requested to clarify whether Warehouse No. 5 is or is not in the license renewal scope, and to provide the technical basis for its determination.

- Part 3

The Unit 2 Sodium Hypochlorite Building is described in Unit 2 FSAR Section 5.6.1. It states "An adjacent Class II building, which houses the chlorination equipment, is isolated from the intake structure by a joint filled with compressible material. General layouts of the intake structure and circulating water system are shown on Figures 5.6 1and 5.6 2, respectively." Based on Unit 2 FSAR Figure 5.6-1, it appears to the staff that failure of the Class 2 building in a seismic event has the potential to damage safety-related structures and components in close proximity. The applicant is requested to submit its technical basis for concluding that the Unit 2 Sodium Hypochlorite Building does not satisfy the criteria of 10 CFR 54.4(a)(2), for inclusion in the license renewal scope.

- Part 4

The following tank foundations are referenced to the FSAR sections noted in parentheses:

Unit 1 Demineralized Water Storage Tank Foundation (Unit 2 FSAR Table 9.12 1)
Unit 2 Condensate Surge Tank Foundation (Unit 2 FSAR Section 2.7.5.1)
Unit 2 Primary Water Storage Tank Foundation (Unit 2 FSAR Table 9.12 1)
Unit 3 Boron Test Tanks Foundation (Unit 3 FSAR Section 9.3.5.2)
Unit 3 Liquid Nitrogen Storage Tank Foundation (Unit 3 FSAR Section 9.2.8.2)
Unit 3 Primary Grade Water Storage Tank Foundation (Unit 3 FSAR Section 9.2.8.3)
Unit 3 Waste Test Tanks Foundation (Unit 3 FSAR Section 11.2.2.1)
Unit 3 Yard Vacuum Priming Tank Foundation (Unit 3 FSAR, FPER 5.5 Analysis 86)

The applicant is requested to verify that none of the systems serviced by these tanks are within the scope of license renewal. If any system is in the license renewal scope, submit the technical basis for concluding that the associated tank and its foundation is not in the license renewal scope.

Dominion Response:

Part 1

Both Millstone Unit 2 and Unit 3 are designed with preferred normal and alternate offsite power supplies, as described in the FSAR sections cited in RAI 2.4-2. The design for offsite power supply includes the main transformers, normal station service transformers, and reserve station service transformers. In addition, the Millstone Unit 2 licensing basis, for general design criterion (GDC) 17 requirements, credits Unit 3 electrical components, including the main transformers, and a normal station service and reserve station service transformer, as an alternate offsite power source. For both units, the emergency onsite power source, i.e., the emergency diesel generators, is the safety-related power source credited in the accident analyses. The emergency onsite power source components are included in the scope of license renewal. The main transformers and normal station service transformers do not meet the scoping criteria of 10CFR54.4(a) and do not perform a license renewal intended function. These transformers do not meet 10CFR54.4(a)(1) since they are non-safety-related components and do not perform safety-related functions. They do not meet 10CFR54.4(a)(2) since their failure cannot prevent the accomplishment of the intended function of any safety-related equipment, and they do not meet 10CFR54.4(a)(3) since they are not credited for any of the cited regulated events. Therefore, the main and normal station service transformers that provide the preferred normal and alternate offsite power supplies to the units are not included within the scope of license renewal.

The reserve station service transformers for both Millstone Unit 2 and Unit 3 are included in scope per 10CFR54.4(a)(3) because they are required for the restoration of offsite power following a station blackout event. The reserve station service transformers foundations are in the scope of license renewal and are included in Unit 2 LRA Table 2.4.2-16 and Unit 3 LRA Table 2.4.2-25 as "Structural Reinforced Concrete".

Part 2

There are two separate and individual site structures that have the designation Warehouse No. 5. These structures are shown on the License Renewal Site Plan (license renewal drawing 25205-LR10025, Sh. 1) as Building No. 212 (Unit 2 Condensate Polishing Facility and Warehouse No. 5) and Building No. 435 (Warehouse #5). Tables 2.2-3 for both Unit 2 and Unit 3 list the Unit 2 Condensate Polishing Facility and Warehouse No. 5, so designated since the Condensate Polishing Facility is located within this building, as being in the scope of license renewal. Unit 2 LRA Section 2.4.2.10 and Unit 3 LRA Section 2.4.2.20 provide a description of this structure and the criteria for which it is considered in the scope of license renewal.

Building No. 435 does not house any equipment or systems that meet the criteria for inclusion in scope of license renewal. Therefore, this building is not in the scope of license renewal and is listed in LRA Table 2.2-4 for both Unit 2 and Unit 3 under Miscellaneous Warehouses (#9, #8, #3, #4, #5, #6).

Part 3

The Unit 2 FSAR Section 5.1.1.1, Class I Structures, states that "Class I structures are designed to withstand the appropriate seismic and other applicable loads without loss of function. These Class I structures are sufficiently isolated or protected from Class II structures to ensure that their integrities are maintained at all times."

The Class II Sodium Hypochlorite Building for Unit 2 is located adjacent to and east of the Class I Intake Structure. Two safety related cable pits are also located adjacent to and east of the Intake Structure, one to the north of and near, the other to the south of and near the Sodium Hypochlorite Building.

The Sodium Hypochlorite Building is a reinforced concrete structure 16 ft. tall with 12-inch-thick walls and a structural steel roof support system. It does not contain any equipment that is in the scope of license renewal and is a robust structure that is unlikely to fail in a seismic event. It is separated from the Intake Structure by a seismic gap filled with compressible material. This compressible material is in the scope of license renewal and subject to aging management. It is included in the Commodity Group "Expansion joint/Seismic gap material (between adjacent buildings/structures)", as indicated in LRA Table 2.4.2-25, Miscellaneous Structural Commodities.

The Class I Intake Structure is a reinforced concrete structure with wall thickness of 1 ft.- 3 in. where it is adjacent to the Sodium Hypochlorite Building wall and is in the scope of license renewal. The Intake Structure is designed and sufficiently isolated or protected from the Class II Sodium Hypochlorite Building to ensure that its integrity is maintained at all times as stated in FSAR Section 5.1.1.1, Class I Structures.

The cable pits are designated safety-related since they house safety-related cables and are concrete bunkers consisting of 12-inch-thick reinforced concrete walls and roof supported on a reinforced concrete foundation. The robust design of the cable pits and separation from the Sodium Hypochlorite Building (1 ft. – 5 ¼ inches) is adequate to ensure that they are sufficiently isolated or protected from the Class II Sodium Hypochlorite Building to ensure that their integrities are maintained at all times.

Based on the statements from FSAR Section 5.1.1.1 and on the robust design and construction of the Sodium Hypochlorite Building including the seismic gap, it is not credible to postulate failure of this structure during a design basis earthquake. Even if such failure is postulated, it will not prevent the Class I Intake Structure or the Cable Pits from performing their respective intended functions. However, to conservatively ensure the integrity of the

Class 1 Intake Structure and the Safety Related Cable Pits, the Sodium Hypochlorite Building will be added to the scope of license renewal. The structure consists of structural reinforced concrete in soil, air, and atmosphere/weather environments and structural steel members in an air environment. The aging effects requiring management are loss of material, cracking, and change of material properties for structural reinforced concrete and loss of material for structural steel. These aging effects will be managed by the Structures Monitoring Program AMP that is described in LRA Section B2.1.23. The aging management review results are included in Table 1.

Part 4

- Unit 1 Demineralized Water Storage Tank Foundation (Unit 2 FSAR Table 9.12-1): The Millstone Unit 1 demineralized water storage tank has been permanently removed from service and is not in the scope of license renewal. Therefore, the tank foundation is not in the scope of license renewal.

- Unit 2 Condensate Surge Tank Foundation (Unit 2 FSAR Section 2.7.5.1): The condensate surge tank is part of the Condensate Storage and Transfer System which is in the scope of license renewal because it meets 10CFR54.4(a)(1) by providing a protected water source for the auxiliary feedwater pumps. The condensate surge tank itself is not the protected water source required to support this license renewal system intended function and is not in the scope of license renewal. Therefore, the associated tank foundation is not in the scope of license renewal.

-Unit 2 Primary Water Storage Tank Foundation (Unit 2 FSAR Table 9.12-1): The primary water storage tank is part of the Primary Makeup Water System, which is in the scope of license renewal. The Primary Makeup Water System meets 10CFR54.4(a)(1) because it includes safety-related instrumentation and provides a containment pressure boundary. The system meets 10 CFR 54.4(a)(2) since the system contains non-safety-related components that are spatially oriented such that their failure could prevent the function of safety-related SSCs. The system also meets 10 CFR 54.4(a)(3) because it contains environmentally qualified equipment. The source of water provided by the tank does not support the system intended functions and the tank was not originally included in the scope of license renewal. However, in response to RAI 2.1-1 the Unit 2 primary water storage tank and foundation were added to the scope of license renewal.

- Unit 3 Boron Test Tanks Foundation (Unit 3 FSAR Section 9.3.5.2): The boron test tanks are part of the Boron Recovery System which is in the scope of license renewal because it meets 10 CFR 54.4(a)(2) since the system contains non-safety-related components that are spatially oriented such that their failure could prevent the function of safety-related SSCs. The system also meets 10 CFR 54.4(a)(3) because it supports fire protection by providing an alternate letdown path to the boron recovery tanks. The boron test tanks themselves do not support the system intended functions and are not in the scope of license renewal. Therefore, the associated foundation is not in the scope of license renewal.

- Unit 3 Liquid Nitrogen Storage Tank Foundation (Unit 3 FSAR Section 9.2.8.2): The liquid nitrogen storage tank is part of the Nitrogen System, which is in the scope of license renewal. The Nitrogen System meets 10 CFR 54.4(a)(1) because it includes safety-related instrumentation and provides a containment pressure boundary. The system meets 10 CFR 54.4(a)(2) since the system contains non-safety-related components that are spatially oriented such that their failure could prevent the function of safety-related SSCs. The system also meets 10 CFR 54.4(a)(3) because it supports fire protection and contains environmentally qualified equipment. However, the liquid nitrogen storage tank itself is not required to support any license renewal system intended functions. Therefore, the liquid nitrogen storage tank and foundation are not included in the scope of license renewal.

- Unit 3 Primary Grade Water Storage Tank Foundation (Unit 3 FSAR Section 9.2.8.3): The primary grade water storage tank is part of the Primary Grade Water System, which is in the scope of license renewal. The Primary Grade Water System meets 10 CFR 54.4(a)(1) because it includes safety-related instrumentation and provides a containment pressure boundary. The system meets 10 CFR 54.4(a)(2) since the system contains non-safety-related components that are spatially oriented such that their failure could prevent the function of safety-related SSCs. The system also meets 10 CFR 54.4(a)(3) because it supports station blackout events and contains environmentally qualified equipment. However, the source of water provided by the primary water storage tanks does not support any license renewal system intended functions. Therefore, the tanks and associated foundation are not included in the scope of license renewal.

- Unit 3 Waste Test Tanks Foundation (Unit 3 FSAR Section 11.2.2.1): The waste test tanks are part of the Radioactive Liquid Waste Processing System which is in the scope of license renewal because it meets 10 CFR 54.4(a)(2) since the system contains non-safety-related components that are spatially oriented such that their failure could prevent the function of safety-related SSCs. The waste test tanks are not located near any SR SSCs and do not perform a license renewal intended function. Therefore, the tanks and associated foundation are not within the scope of license renewal.

- Unit 3 Yard Vacuum Priming Tank Foundation (Unit 3 FSAR, FPER 5.5 Analysis 86): The yard vacuum priming tank is part of the Vacuum Priming System which is not in the scope of license renewal since it does not meet any of the criteria of 10 CFR 54.4(a). Therefore, the yard vacuum priming tank and associated foundation are not in the scope of license renewal.

Table 1: Unit 2 Sodium Hypochlorite Building

Structural Member	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Volume 2 Item	Table 1 Item	Notes
Structural Reinforced Concrete	SNS	Concrete	(E) Air	Change of Material Properties	Structures Monitoring Program			H
				Cracking	Structures Monitoring Program	III.A6.1-c	3.5.1-22	A
			(E) Atmosphere/Weather	Change of Material Properties	Structures Monitoring Program			H
				Cracking	Structures Monitoring Program	III.A6.1-a	3.5.1-22	A
					Structures Monitoring Program	III.A6.1-c	3.5.1-22	A
				Loss of Material	Structures Monitoring Program	III.A6.1-a	3.5.1-22	A
			(E) Soil	Change of Material Properties	Structures Monitoring Program	III.A6.1-e	3.5.1-22	A
				Cracking	Structures Monitoring Program	III.A6.1-e	3.5.1-22	A
					Structures Monitoring Program	III.A6.1-d	3.5.1-22	A
				Loss of Material	Structures Monitoring Program	III.A6.1-e	3.5.1-22	A
					Structures Monitoring Program	III.A6.1-d	3.5.1-22	A
Structural Steel	SNS	Carbon Steel	(E) Air	Loss of Material	Structures Monitoring Program	III.A6.2-a	3.5.1-22	A

RAI 3.1.1-1A (Unit 2)

NUREG-1801, section IVA2.8-b states that the pressure vessel skirt support, cantilever/column support and neutron shield tank is subject to loss of material due to boric acid corrosion. Include this aging effect and the necessary aging management programs (AMPs) for these components concerning loss of material due to boric acid corrosion in Table 3.1.2-1 of the LRA or provide justification for concluding that boric acid corrosion is not an aging effect.

Dominion Response:

The structural supports for major reactor coolant system components are evaluated separately from the component and its integral parts, as NSSS Equipment Supports, as described in LRA Section 2.1.5.3, Structural Screening. There is no skirt support, cantilever/column support, or neutron shield tank components for the Millstone Unit 2 reactor vessel support system. The Millstone Unit 2 reactor pressure vessel supports are identified as structural members "Reactor Vessel Support: Bolting", "Reactor Vessel Support: Plate and Structural Shapes", and "Reactor Vessel Support: Sliding Support Assembly" in LRA Table 3.5.2-24 on pages 3-528 and 3-529, respectively. Loss of material (due to boric acid corrosion) is identified for these structural members consistent with NUREG-1801 item III.B1.1.1-b, and is managed with the Boric Acid Corrosion and General Condition Monitoring aging management programs.

RAI 3.1.1-1B (Unit 3)

NUREG-1801, section IVA2.8-b states that the pressure vessel skirt support, cantilever/column support and neutron shield tank is subject to loss of material due to boric acid corrosion. Include this aging effect and the necessary aging management programs for these components concerning loss of material due to boric acid corrosion in Table 3.1.2-1 of the LRA or provide justification for concluding that boric acid corrosion is not an aging effect.

Dominion Response:

The structural supports for major reactor coolant system components are evaluated separately from the component and its integral parts, as NSSS Equipment Supports, as described in LRA Section 2.1.5.3, Structural Screening. There is no skirt support or cantilever/column support components for the Millstone Unit 3 reactor vessel support system. The Millstone Unit 3 reactor pressure vessel supports are identified as structural members "Reactor Vessel Support: Bolting", "Reactor Vessel Support: Neutron Shield Tank Assembly", "Reactor Vessel Support: Plate and Structural Shapes", and "Reactor Vessel Support: Sliding Support Plate" in LRA Table 3.5.2-35 on pages 3-640 and 3-641, respectively. Loss of material (due to boric acid corrosion) is identified for these structural members consistent with NUREG-1801 Volume 2 item III.B1.1.1-b, and is managed with the Boric Acid Corrosion and General Condition Monitoring aging management programs.

RAI 3.1.1-2A (Unit 2)

Table 3.1.2-1 of the LRA does not specify loss of material/wear for the closure head stud assembly as required by NUREG-1801, section IVA.2.1-d. Include this aging effect and the corresponding aging management program (AMP XI.M3 of NUREG-1801 "Reactor Head Closure Studs") in Table 3.1.2-1 of the LRA or provide justification for concluding that loss of material/wear is not an aging effect.

Dominion Response:

The closure head stud assembly does not experience relative motion other than normal stud removal and installation during refueling activities. These activities are closely monitored by procedure and any degradation is dispositioned by supplemental examination, corrective measures or repairs, analytical evaluation of the component function, or replacement of the component to ensure continued structural integrity and function of the component. There is no significant continuing wear to the reactor vessel closure head studs that would lead to a loss of component function and require monitoring by an aging management program. Therefore, loss of material due to wear was not considered an applicable aging effect for the closure head stud assembly.

RAI 3.1.1-2B (Unit 3)

Table 3.1.2-1 of the LRA does not specify loss of material/wear for the closure head stud assembly as required by NUREG-1801, section IVA.2.1-d. Include this aging effect and the corresponding aging management program (AMP XI.M3 of NUREG-1801 "Reactor Head Closure Studs") in Table 3.1.2-1 of the LRA or provide justification for concluding that loss of material/wear is not an aging effect.

Dominion Response:

The closure head stud assembly does not experience relative motion other than normal stud removal and installation during refueling activities. These activities are closely monitored by procedure and any degradation is dispositioned by supplemental examination, corrective measures or repairs, analytical evaluation of the component function, or replacement of the component to ensure continued structural integrity and function of the component. There is no significant continuing wear to the reactor vessel closure head studs that would lead to a loss of component function and require monitoring by an aging management program. Therefore, loss of material due to wear was not considered an applicable aging effect for the closure head stud assembly.

RAI 3.1.1-3A (Unit 2)

Table 3.1.2-1 of the LRA does not specify loss of fracture toughness/neutron irradiation embrittlement for the upper shell as required by NUREG-1801, section IVA.2.5-c. Include this aging effect and the corresponding aging management program (AMP XI.M31 of NUREG-1801 "Reactor Vessel Surveillance") in Table 3.1.2-1 of the LRA or provide justification for concluding that fracture toughness/neutron irradiation embrittlement is not an aging effect.

Dominion Response:

Loss of fracture toughness due to neutron irradiation embrittlement is an applicable aging effect for those reactor pressure vessel subcomponents exposed to a neutron fluence greater than 1 x 10^{17} n/cm^2 (E > 1 MeV). This threshold level of fluence is experienced by the beltline region subcomponents identified in LRA Table 3.1.2-1 as susceptible to loss of fracture toughness. Additionally, based on a supplemental evaluation of the limits of the beltline region performed to account for the period of extended operation, the upper shell, identified as Upper Shell (and cladding) in LRA Table 3.1.2-1 and primary outlet nozzles, identified as Primary Nozzles and Safe Ends (and cladding) in LRA Table 3.1.2-1 and associated welds, are subject to loss of fracture toughness due to neutron irradiation embrittlement and will be managed with the Reactor Vessel Surveillance AMP.

RAI 3.1.1-3B (Unit 3)

Table 3.1.2-1 of the LRA does not specify loss of fracture toughness/neutron irradiation embrittlement for the upper shell as required by NUREG-1801, section IVA.2.5-c. Include this aging effect and the corresponding aging management program (AMP XI.M31 of NUREG-1801 "Reactor Vessel Surveillance") in Table 3.1.2-1 of the LRA or provide justification for concluding that fracture toughness/neutron irradiation embrittlement is not an aging effect.

Dominion Response:

Loss of fracture toughness due to neutron irradiation embrittlement is an applicable aging effect for those reactor pressure vessel subcomponents exposed to a neutron fluence greater than 1×10^{17} n/cm^2 (E > 1 MeV). This threshold level of fluence is experienced by the beltline region subcomponents identified in LRA Table 3.1.2-1 as susceptible to loss of fracture toughness. Additionally, based on a supplemental evaluation of the limits of the beltline region performed to account for the period of extended operation, the upper shell, identified as Upper (Nozzle) Shell (and cladding) in LRA Table 3.1.2-1 and primary inlet nozzles, identified as Primary Nozzles (and cladding) in LRA Table 3.1.2-1 and associated welds, are subject to loss of fracture toughness due to neutron irradiation embrittlement and will be managed with the Reactor Vessel Surveillance AMP.

RAI 3.1.1-4B (Unit 3)

NUREG 1801, section IVB2.6-b specifies void swelling as an aging affect for the BMI guide tubes. Therefore, Table 3.2.1-1 of the LRA should specify void swelling as an aging effect for the BMI guide tubes and provide a plant specific aging management program as required by NUREG-1801 or provide justification for concluding that void swelling is not an aging effect.

Dominion Response:

NUREG-1801 item IV.B2.6-b refers to the flux thimble guide tubes that are a part of the reactor vessel internals instrumentation support structure. This subcomponent is included in Millstone Unit 3 LRA Table 3.1.2-2 as "BMI Columns". Change in dimension due to void swelling and NUREG-1801 item IV.B2.6-b have been identified for the BMI columns. Aging management is provide by the Inservice Inspection Program: Reactor Vessel Internals aging management program. The BMI guide tubes listed in Millstone Unit 3 LRA Table 3.1.2-1 are external to the reactor vessel and are not subject to void swelling. There is no LRA Table 3.2.1-1

RAI 3.1.2-1A (Unit 2)

Table 3.1.2-1 of the LRA does not specify loss of material/wear for the vessel flange and core support ledge as required by NUREG-1801, section IVA.2.5-f. The aging effect and the corresponding aging management program required by NUREG-1801 (AMP XI.M1, "Inservice inspection") should be included in the LRA or provide justification for concluding that loss of material/wear is not an aging effect.

Dominion Response:

The reactor vessel flange and core support ledge does not experience relative motion other than normal reactor disassembly and reassembly during refueling activities. These activities are closely monitored by procedure and any degradation is dispositioned by supplemental examination, corrective measures or repairs, or analytical evaluation of the component function to ensure continued structural integrity and function of the component. There is no significant continuing wear to the reactor vessel flange and core support ledge that would lead to a loss of component function that would require monitoring by an aging management program. Therefore, loss of material due to wear was not considered an applicable aging effect for the reactor vessel flange and core support ledge.

RAI 3.1.2-1B (Unit 3)

Table 3.1.2-1 of the LRA does not specify loss of material/wear for the vessel flange and core support ledge as required by NUREG-1801, section IVA.2.5-f. The aging effect and the corresponding aging management program required by NUREG-1801 (AMP XI.M1, "Inservice inspection") should be included in the LRA or provide justification for concluding that loss of material/wear is not an aging effect.

Dominion Response:

The reactor vessel flange and core support ledge does not experience relative motion other than normal reactor disassembly and reassembly during refueling activities. These activities are closely monitored by procedure and any degradation is dispositioned by supplemental examination, corrective measures or repairs, or analytical evaluation of the component function to ensure continued structural integrity and function of the component. There is no significant continuing wear to the reactor vessel flange and core support ledge that would lead to a loss of component function that would require monitoring by an aging management program. Therefore, loss of material due to wear was not considered an applicable aging effect for the reactor vessel flange and core support ledge.

RAI 3.1.2-2A (Unit 2)

Table 3.1.2-2 of the LRA does not specify loss of fracture toughness/neutron irradiation embrittlement for the core support barrel upper flange as required by section IVB.3.3-a. The aging effect and the corresponding aging management program (AMP XI.M16 of NUREG-1801 "PWR Vessel Internals") should be included in the LRA or provide justification for concluding that fracture toughness/neutron irradiation embrittlement is not an aging effect.

Dominion Response:

The stainless steel reactor vessel internal subcomponents most susceptible to the effects of irradiation embrittlement are those nearest the reactor core. As indicated in LRA Table 3.1.2-2, the loss of fracture toughness aging effect has been applied for the subcomponents nearest to the reactor core. Aging management for these subcomponents is provided by the Inservice Inspection Program: Reactor Vessel Internals AMP. These stainless steel subcomponents are subject to high neutron fluence and would act as leading indicators for the aging effect. Due to the location of the stainless steel core support barrel upper flange, and the distance from the reactor core, loss of fracture toughness due to neutron irradiation embrittlement is not expected to be significant.

However, as part of the aging management program for the reactor vessel internals, Dominion has committed to following the industry efforts related to internals aging issues, including neutron irradiation embrittlement. This commitment is described in LRA Appendix B, Section B2.1.17 "Inservice Inspection Program: Reactor Vessel Internals" and in LRA Appendix A, Table A6.0-1, item 13, as revised by AMR audit Item #6 in a letter to NRC, S/N: 04-320 dated 7/7/04.

RAI 3.1.2-3A (Unit 2)

Table 3.1.2-2 of the LRA does not specify the loose parts monitoring AMP to manage the loss of preload/stress relaxation aging effect for the CEA shroud bolts as required by NUREG-1801, section IVB.3.2-g. Provide this aging management program or provide justification for not including this AMP.

Dominion Response:

The bolted connections in the reactor vessel internals are managed for the effects of loss of preload by the Inservice Inspection Program: Reactor Vessel Internals AMP as indicated in LRA Table 3.1.2-2. The Inservice Inspection Program: Reactor Vessel Internals AMP provides for internals inspections in accordance with examination category B-N-3 of the ASME Code, Section XI, Subsection IWB. These inspections include VT-3 examinations of the bolted connections to detect a gross loss of preload, such as looseness and improper fit, prior to failure of the connection. Therefore, management of loss of preload by the Inservice Inspection Program: Reactor Vessel Internals AMP provides reasonable assurance that degradation would be detected prior to the loss of the intended function.

Millstone does not rely upon Loose Parts Monitoring Program as suggested in NUREG-1801, item IV.B3.2-g, since this approach would require failure of the bolting in order to be effective.

RAI 3.1.2-4-1

The applicant identifies the GALL in-service inspection AMP, XI.M1 as the AMP to manage the aging effect of cracking in the base support and flange, support brackets and lugs for Unit 3. The GALL in-service inspection AMP, XI.M1, does not address the base support and flange, support brackets and lugs. Therefore, the applicant must provide details for the following aging management program attributes for these components: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria.

Dominion Response:

The identified steam generator support configuration is applicable to Millstone Unit 2. Table 3.1.2.4 (Page 3-88) of the Millstone Unit 2 License Renewal Application (LRA) does credit the Millstone Inservice Inspection Program: Systems, Components and Supports Aging Management Program (AMP) for managing the aging effect of cracking for the steam generator support and flange, support brackets and lugs.

The Scope of Program for NUREG-1801, Section XI.M1 identifies that the scope includes "all pressure retaining components and their integrally welded attachments." The integral weld attachment of the base support to the steam generators is included under ASME Section XI, Subsection IWB. The rest of the support configuration is included under ASME Section XI, Subsection IWF. LRA Table B2.0 identifies the correlation between the NUREG-1801 (GALL) programs and the Millstone AMPs. On page B-5 of this Table, Section XI.M1, ASME Section XI Inservice Inspections, Subsections IWB, IWC, and IWD of NUREG-1801 corresponds to the Millstone Inservice Inspection Program: Systems, Components and Supports AMP. Similarly, on page B-7 of this Table, Section XI.S3, ASME Section XI, Subsection IWF (for Supports) also corresponds to the same Millstone AMP. Since NUREG-1801, XI.M1 and XI.S3 are both addressed by the same Millstone AMP for managing the aging effect of cracking for the steam generator support and flange, support brackets and lugs, these items do not need to be separately described in terms of Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria.

RAI 3.1.2-4-2

Table 3.1.2-4: Reactor Vessel, Internals, and Reactor Coolant System - Steam Generator - Aging Management Evaluation Unit 2. In GALL IV.D1.1-j and GALL IV.D1.2-j, the staff identifies primary water stress corrosion cracking (PWSCC) as an aging effect for the primary instrument nozzles and tube plugs under treated water, respectively. Table 3.1.2-4 of the applicant's LRA indicates that the aging effect is cracking. The staff requests the applicant to identify the mechanism for cracking in the primary instrument nozzles and tube plugs (e.g., PWSCC, ODSCC, etc.). If the mechanism is not consistent with GALL, the applicant should discuss how the aging effect is managed.

Dominion Response:

Consistent with referenced NUREG-1801 items IV.D1.1-j and IV.D1.2-j, the cracking mechanism for the primary instrument nozzles and tube plugs subcomponents shown in Millstone Unit 2 LRA Table 3.1.2-4 is primary water stress corrosion cracking (PWSCC).

RAI 3.1.2-4-3

In GALL IV.D1.1-I, the staff identifies stress corrosion cracking (SCC) as an aging effect and Bolting Integrity as the AMP for the primary manway bolting in the air environment. However, for this component, the applicant identifies the aging effect as cracking and the Inservice Inspection as the AMP. The staff requests the applicant to clarify the mechanism for cracking and how the Inservice Inspection AMP is used to manage this aging effect similar to the GALL recommended Bolting Integrity AMP.

Dominion Response:

In response to NRC staff concerns with the approach to management of bolting aging effects described in the LRA, Millstone has developed a Bolting Integrity aging management program, which will be used to manage aging effects for closure bolting in the steam generator primary manway, instead of the Inservice Inspection Program: Systems, Components and Supports AMP. The Bolting Integrity AMP is described in the response to RAI 3.3.11-A-1.

RAI 3.1.2-4-4

In GALL IV.D1.1-f, the staff identifies loss of preload and stress relaxation as the aging effects for secondary manway and handhole bolting in the air environment. For this component, the applicant identifies the only aging effect as cracking and the Inservice Inspection as the AMP. The staff requests the applicant to justify why loss of preload and stress relaxation are not applicable aging effects and if these aging effects are applicable, how these are managed.

Dominion Response:

At Millstone Units 2 and 3, loss of pre-load is not an aging effect for secondary manway and handhole bolting. Millstone Units 2 and 3 use only SA-193, Grade B7 bolting for these applications. Based on ASME B&PV Code (1992 ed.), Section II, Part D, Table 4, stress relaxation need not be considered for the SA-193, Grade B7 bolting at service temperatures less than 700°F. The normal operating reactor coolant system hot leg temperature, which bounds the maximum operating temperature for the steam generator secondary side components, is 600.5°F for Unit 2 and 618°F for Unit 3. This temperature is below the 700°F threshold temperature for stress relaxation concerns with this material. Therefore, loss of preload due to stress relaxation of the secondary manway and handhole bolting is not an aging effect requiring management and no aging management program is required.

RAI 3.1.2-4-5 (Unit 2)

Table 3.1.2-4 of the applicant's LRA states that the aging effect for the tube support lattice rings is loss of material. The staff believes cracking is also a potential aging effect. The staff requests the applicant to justify why cracking is not considered an aging effect for the tube support lattice rings under treated water and steam.

Dominion Response:

The carbon steel tube support lattice rings are non-pressure boundary steam generator secondary-side components exposed to a treated water and steam environment. As described in LRA Appendix C, Section C3.3.9, cracking due to flaw initiation and growth was considered a potential aging effect only for ASME Class 1 components and pressure boundary components on the secondary side of the steam generators. Additionally, LRA Appendix C, Section C3.3.15 discusses cracking due to stress-corrosion and indicates that only high-strength carbon steel components such as bolting are susceptible to this aging mechanism. These components are not fabricated from high-strength carbon steel and are not susceptible to stress-corrosion cracking in the steam generator secondary-side environment. As such, cracking is not identified as an aging effect requiring management for the tube support lattice rings in LRA Table 3.1.2-4.

RAI 3.1.2-4A (Unit 2)

Table 3.1.2-2 of the Millstone, Unit 2, LRA specifies core support barrel snubber assemblies with the following aging effects: void swelling, loss of fracture toughness, and loss of material/wear. Figure 3.3-12 of the FSAR shows bolts for this assembly. Do these aging effects also apply to the bolts? Provide the associated AMPs or justification for concluding that these bolts are not subject to these aging effects. Also, is loss of preload an aging effect of these bolts? Provide an appropriate AMP or justification for concluding that these bolts are not subject to loss of preload.

Dominion Response:

The aging effects shown in Millstone Unit 2 LRA Table 3.1.2-2 for the core support barrel snubber assemblies applied to all parts of the assembly, including the bolts. The applicable aging management programs are the Inservice Inspection Program: Reactor Vessel Internals, and the Chemistry Control for Primary Systems Program, as indicated in LRA Table 3.1.2-2 on page 3-57. The loss of preload aging effect was inadvertently omitted from LRA Table 3.1.2-2 for this assembly. The Inservice Inspection Program: Reactor Vessel Internals manages loss of preload for this bolting through VT-3 examinations in accordance with examination category B-N-3.

RAI 3.1.2-5A (Unit 2)

Table 3.1.2-2 of the Millstone, Unit 2, LRA specifies core shroud assembly fabricated from stainless steel. Figure 3.3-13 of the FSAR shows the core shroud assembly consists of a lower segment and an upper segment joined by tie rod assemblies. Are there welds in the individual segments of the core shroud? If the core shroud segments are bolted, provide the aging effects, including loss of preload for these core shroud assembly bolts and the associated AMP. If these core shroud segments are welded, are the welds and adjacent base material susceptible to irradiation assisted stress corrosion cracking (IASCC)? Provide the appropriate AMP for IASCC (including type of inspection, inspection frequency and acceptance criteria) or provide justification for concluding that these welds and adjacent base material are not susceptible to IASCC.

Dominion Response:

The Millstone Unit 2 core shroud assembly upper segment and lower segment are weldments and do not include bolting. The welds are included as part of the core shroud assembly subcomponent in LRA Table 3.1.2-2 and are subject to the aging effects identified for this subcomponent, which includes cracking consistent with NUREG-1801, item IV.B3.4-a (Crack initiation and growth / Stress corrosion cracking, irradiation-assisted stress corrosion cracking). Aging management for cracking is provided by the Chemistry Control for Primary Systems Program and Inservice Inspection Program: Reactor Vessel Internals AMPs.

RAI 3.1.2-6A (Unit 2)

Section 3.1.2.2.7.1 of the LRA states that the reactor vessel flange leak detection line is not within the scope of license renewal because it does not meet the criteria of 10 CFR 54.4(a) as an intended function. However, NUREG-1801, section IV A.2.1 -f specifies this component is in scope and is subject to a crack initiation and growth/stress corrosion cracking aging mechanism. Therefore, provide a plant specific aging management program as required by NUREG-I801 for cracking of this component.

Dominion Response:

The reactor vessel leak detection system, including the leak detection line, is not in the scope of license renewal. As stated on Page 3-18 in the Unit 2 LRA, the reactor vessel closure head and shell flanges are sealed by inner and outer hollow metallic O-rings. Any leakage through this seal arrangement is directed to the leakage detection system through a 3/16" hole in the vessel flange. Leakage flow past the inner reactor vessel flange O-ring is limited in the event of seal failure by the 3/16" diameter hole in the reactor vessel flange which is smaller than the inside diameter of the leak detection line. Additionally, the potential flowrate through the 3/16" diameter hole in the flange is within the normal make-up capability of the Chemical and Volume Control System such that the leak detection system does not constitute the RCS pressure boundary. The failure of the leak detection system components has been evaluated and cannot affect the function of SR SSCs. As such, the reactor vessel flange seal leak detection system, including the leak detection line does not meet the criteria of 10CFR54.4(a) and is not within the scope of license renewal. Therefore, the system is not subject to aging management review and there is no aging management program applicable to the leak detection line.

RAI 3.1.2-6B (Unit 3)

Section 3.1.2.2.7.1 of the LRA states that the reactor vessel flange leak detection line is not within the scope of license renewal because it does not meet the criteria of 10 CFR 54.4(a) as an intended function. However, NUREG-1801, section IV A.2.1-f specifies this component is in scope and is subject to a crack initiation and growth / stress corrosion cracking aging mechanism. Therefore, provide a plant specific aging management program as required by NUREG-1801 for cracking of this component.

Dominion Response:

The reactor vessel leak detection system, including the leak detection line, is not in the scope of license renewal. As stated on Page 3-19 in the Unit 3 LRA, the reactor vessel closure head and shell flanges are sealed by inner and outer hollow metallic O-rings. Any leakage through this seal arrangement is directed to the leakage detection system through a 1/8" hole in the vessel flange. Leakage flow past the inner reactor vessel flange O-ring is limited in the event of seal failure by the 1/8" diameter hole in the reactor vessel flange which is smaller than the inside diameter of the leak detection line. Additionally, the potential flowrate through the 1/8" diameter hole in the flange is within the normal make-up capability of the Chemical and Volume Control System such that the leak detection system does not constitute the RCS pressure boundary. The failure of the leak detection system components has been evaluated and cannot affect the function of SR SSCs. As such, the reactor vessel flange seal leak detection system, including the leak detection line does not meet the criteria of 10CFR54.4(a) and is not within the scope of license renewal. Therefore, the system is not subject to aging management review and there is no aging management program applicable to the leak detection line.

RAI 3.1.2-7

Table 3.1.2-2 of the Millstone unit 2 LRA does not specify a hold down ring that is subject to loss of material/wear. Include this aging effect and the necessary aging management programs in the LRA for this component as required by NUREG-1801, item IV.B.3.1.4.

Dominion Response:

The hold down ring for the Millstone Unit 2 reactor vessel internals is identified as subcomponent "Expansion Compensating Ring" in LRA Table 3.1.2-2. The aging effect of loss of material is identified for this subcomponent consistent with NUREG-1801 for item IV.B.3.1.4.

RAI 3.1.2-8

Table 3.1.2-2 of the Millstone unit 2 LRA does not specify core shroud assembly bolts that are subject to fatigue, cracking, void swelling, loss of fracture toughness, and loss of preload. Include these aging effects and the necessary aging management programs in the LRA for this component as required by NUREG-1801, item IV.B.3.4.2.

Dominion Response:

The core shroud assembly for the Millstone Unit 2 reactor vessel internals utilizes welded construction and there are no core shroud assembly bolts. Therefore, NUREG-1801 item IV.B.3.4.2 is not applicable.

RAI 3.1.2-9

Table 3.1.2-2 of the Millstone unit 2 LRA does not specify core support column bolts that are subject to fatigue, cracking/IASCC, void swelling, and loss of fracture toughness. Include these aging effects and the necessary aging management programs in the LRA for this component as required by NUREG-1801, item IV.B.3.5.5.

Dominion Response:

The core support columns for the Millstone Unit 2 reactor vessel internals utilize welded construction and there are no core support column bolts. Therefore, NUREG-1801 item IV.B.3.5.5 is not applicable.

RAI 3.1.3-1A (Units 2 & 3)

Table 3.1.2-3 of the LRA specifies the use of AMP B2.1.18, "Inservice Inspection Program: Systems, Components and Supports," for closure bolting in the reactor coolant pump, valves and pressurizer manways. In addition, section B2.0 of Appendix B of the LRA states that the aging management review did not identify the need for the "Bolting Integrity" AMP. However, NUREG-1801, sections IVC2.3-e, IVC2.3-g, IVC2.4-e, IVC2.4-g, IVC2.5-n and IVC2.5-p specifies the use of AMP XI.M18, "Bolting Integrity" for these components. AMP XI.M18 of NUREG-1801 incorporates the requirements and guidelines of NUREG-1339, EPRI NP-5769 and EPRI TR-104213 concerning material selection, bolting preload control, inservice inspections, plant operation and maintenance, and evaluation of the structural integrity of bolted joints. Therefore, the applicant is requested to provide the Bolting Integrity AMP as required by NUREG-1801, or include all of the necessary information discussed above into AMP B2.1.18 of the LRA.

Dominion Response:

In response to NRC staff concerns with the approach to management of bolting aging effects described in the LRA, Millstone has developed a specific Bolting Integrity AMP, which will be used to manage aging effects for closure bolting in the reactor coolant pump, valves, and pressurizer manway, instead of the Inservice Inspection Program: Systems, Components and Supports AMP. The Bolting Integrity AMP is described in the response to RAI 3.3.11-A-1.

RAI 3.1.3-1B (Unit 3)

Table 3.1.2-3 of the LRA specifies the use of AMP B2.1.18, "Inservice Inspection Program: Systems, Components and Supports," for the pressurizer manway closure bolting. In addition, section B2.0 of Appendix B of the LRA states that the aging management review did not identify the need for the "Bolting Integrity" AMP. However, NUREG-1801, section IVC2.5-p specifies the use of AMP XI.M18, "Bolting Integrity" for this component. AMP XI.M18 of NUREG-1801 incorporates the requirements and guidelines of NUREG-1339, EPRI NP-5769 and EPRI TR-104213 concerning material selection, bolting preload control, inservice inspections, plant operation and maintenance, and evaluation of the structural integrity of bolted joints. Therefore, the applicant is requested to provide the Bolting Integrity AMP as required by NUREG-1801, or include all of the necessary information discussed above into AMP B2.1.18 of the LRA.

Dominion Response:

In response to NRC staff concerns with the approach to management of bolting aging effects described in the LRA, Millstone has developed a specific Bolting Integrity AMP, which will be used to manage aging effects for closure bolting in the pressurizer manway, instead of the Inservice Inspection Program: Systems, Components and Supports AMP. The Bolting Integrity AMP is described in the response to RAI 3.3.11-A-1.

RAI 3.1.3-2A (Unit 2)

The CASS spray head assembly identified in Table 3.1.2-3 of the LRA specified the Chemistry Control AMP to manage cracking. NUREG-1801, section IVC2.5-j requires a plant-specific AMP to be used to manage cracking. Therefore, provide this AMP to the NRC for evaluation as required by NUREG-1801, section IVC2.5-j.

Dominion Response:

The material identified in Millstone Unit 2 LRA Table 3.1.2-3 for the pressurizer spray head is nickel-based alloys and not CASS. The plant specific aging management program specified in LRA Table 3.1.2-3 for managing aging effects associated with the pressurizer spray head is the Chemistry Control for Primary Systems Program. In addition, Dominion intends to replace the Unit 2 pressurizer during the Fall 2006 refueling outage. The replacement pressurizer will be constructed of PWSCC-resistant materials as described in the Dominion letter S/N 04-140 to the U. S. Nuclear Regulatory Commission dated June 3, 2004.

RAI 3.1.3-2B (Unit 3)

The CASS spray head assembly identified in Table 3.1.2-3 of the LRA specified the Water Chemistry Control AMP to manage cracking. NUREG-1801, section IVC2.5-j requires a plant-specific AMP to be used to manage cracking. Therefore, provide this AMP to the NRC for evaluation as required by NUREG-1801, section IVC2.5-j.

Dominion Response:

The plant specific aging management program specified in Millstone Unit 3 LRA Table 3.1.2-3 for managing aging effects associated with the CASS pressurizer spray head is the Chemistry Control for Primary Systems Program. The reactor coolant system stainless steel materials, including the pressurizer spray head, are exposed internally to a high-quality primary water and/or steam environment that is not expected to result in significant stress corrosion cracking. The Chemistry Control for Primary Systems Program AMP provides reasonable assurance that cracking resulting from SCC will not prevent the spray head from performing its intended function.

RAI 3.1.3-3B (Unit 3)

Specify which of these components (safe-ends for surge, spray, relief and safety) in Table 3.1.2-3 of the LRA are nickel based and which are stainless steel in order to determine which components to determine the appropriate AMP for primary water stress corrosion cracking as required by NUREG-1801, section IVC2.5-k. In addition, is the surge line nozzle and safe end cast austenitic stainless steel (CASS)? If the component is CASS, then provide a plant-specific aging management program for cracking as required by NUREG-1801, section IVC2.5-i.

Dominion Response:

The safe ends for the Millstone Unit 3 pressurizer surge, spray, relief, and safety nozzles are fabricated from stainless steel. The transition welds between these stainless steel safe ends and the low alloy steel of the pressurizer nozzles are nickel-based alloy. Neither the surge line nozzle nor the safe-end is fabricated from CASS.

The aging effect of cracking for these components is managed by the Chemistry Control for Primary Systems Program and the Inservice Inspection Program: Systems, Components, and Supports AMP.

RAI 3.1.3-4A

Table 3.1.2-3 of the Millstone unit 2 LRA does not specify the pressurizer integral support that is subject to fatigue, cracking/IASCC, and boric acid corrosion. Include these aging effects and provide the necessary aging management programs in the LRA for this component as required by NUREG-1801, item IV.C.2.5.12.

Dominion Response:

The integral supports are identified as component type "Pressurizer (Seismic Lugs)" and "Pressurizer (Support Skirt and Flange)" in Millstone Unit 2 LRA Table 3.1.2-3 on pages 3-78 and 3-79, respectively. The aging effects of loss of material (due to boric acid corrosion) and cracking are identified for these component types consistent with NUREG-1801 for item IV.C.2.5.12. Fatigue is addressed as a TLAA as identified in LRA Table 3.1.1, Item 3.1.1-01.

RAI 3.1.3-4B

Table 3.1.2-3 of the Millstone unit 2 LRA does not specify the pressurizer integral support that is subject to fatigue, cracking/IASCC, and boric acid corrosion. Include these aging effects and provide the necessary aging management programs in the LRA for this component as required by NUREG-1801, item IV.C.2.5.12.

Dominion Response:

Although the RAI refers to Millstone Unit 2 LRA, it is assumed that the intent is to refer to Unit 3 LRA Table 3.1.2-3 since there is a duplicate RAI for Unit 2.

The integral supports are identified as component type "Pressurizer (Seismic and Valve Support Lugs)" and "Pressurizer (Support Skirt and Flange)" in Millstone Unit 3 LRA Table 3.1.2-3 on pages 3-86 and 3-87, respectively. The aging effects of loss of material (due to boric acid corrosion) and cracking are identified for these component types consistent with NUREG-1801 for item IV.C.2.5.12. Fatigue is addressed as a TLAA as identified in LRA Table 3.1.1, Item 3.1.1-01.

RAI 3.1-A-1 (Unit 2)

For materials such as stainless steel and nickel-based alloys in the RV, RV internals, RCS piping or pressurizer components internally exposed to treated water, the applicant lists loss of material as an aging effect requiring management. Justify why the Chemistry Control for Primary Systems Program alone is sufficient to manage loss of material without the need to credit an inspection-based AMP to verify that the Chemistry Control Program is accomplishing its mitigative aging management function. Include how the implementation of the Water Chemistry Control for Primary Systems Program relates to the management of the specific aging mechanisms that are capable of inducing loss of material in the components. If the Chemistry Control for Primary Systems Program alone is not sufficient to manage all the aging mechanisms leading to loss of material in any of the components, propose an acceptable inspection-based AMP for management of loss of material that is applicable to the specific RV, RV internal, RCS piping or pressurizer component.

Dominion Response:

Stainless steel and nickel-based alloy materials in the reactor vessel, reactor vessel internals, and reactor coolant system (RCS) components that are exposed internally to primary water (treated water) are not expected to be subject to significant loss of material as a result of corrosion. NUREG-1801, Generic Aging Lessons Learned Report, does not identify loss of material due to corrosion as an aging effect requiring management for these RCS materials in the primary water internal environment based upon the administrative controls placed on RCS water quality through on-going industry experience. However, loss of material was conservatively considered in the Millstone LRA for the RCS components in the primary water environment. The Chemistry Control for Primary Systems Program provides reasonable assurance that loss of material resulting from corrosion will not prevent these components from performing their intended functions.

Verification of the effectiveness of the Chemistry Control for Primary Systems Program is provided by the Work Control Process as described in LRA Appendix B, Section B2.1.5. The Work Control Process provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities on an ongoing basis. The Work Control Process provides input to the corrective action program if aging effects are identified. The corrective action program evaluates the cause and extent of the condition and, if required, recommends enhancements to ensure continued effectiveness of the Chemistry Control for Primary Systems Program.

RAI 3.1-B-1 (Unit 3)

Reactor Vessel, Internals, and Reactor Coolant System For materials such as stainless steel and nickel-based alloys in the RV, RV internals, RCS piping or pressurizer components internally exposed to treated water, the applicant lists loss of material as an aging effect requiring management. Justify why the Chemistry Control for Primary Systems Program alone is sufficient to manage loss of material without the need to credit an inspection-based AMP to verify that the Chemistry Control Program is accomplishing its mitigative aging management function. Include how the implementation of the Water Chemistry Control for Primary Systems Program relates to the management of the specific aging mechanisms that are capable of inducing loss of material in the components. If the Chemistry Control for Primary Systems Program alone is not sufficient to manage all the aging mechanisms leading to loss of material in any of the components, propose an acceptable inspection-based AMP for management of loss of material that is applicable to the specific RV, RV internal, RCS piping or pressurizer component.

Dominion Response:

Stainless steel and nickel-based alloy materials in the reactor vessel, reactor vessel internals, and reactor coolant system (RCS) components that are exposed internally to primary water (treated water) are not expected to be subject to significant loss of material as a result of corrosion. NUREG-1801, Generic Aging Lessons Learned Report, does not identify loss of material due to corrosion as an aging effect requiring management for these RCS materials in the primary water internal environment based upon the administrative controls placed on RCS water quality through on-going industry experience. However, loss of material was conservatively considered in the Millstone LRA for the RCS components in the primary water environment. The Chemistry Control for Primary Systems Program provides reasonable assurance that loss of material resulting from corrosion will not prevent these components from performing their intended functions.

Verification of the effectiveness of the Chemistry Control for Primary Systems Program is provided by the Work Control Process as described in LRA Appendix B, Section B2.1.5. The Work Control Process provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities on an ongoing basis. The Work Control Process provides input to the corrective action program if aging effects are identified. The corrective action program evaluates the cause and extent of the condition and, if required, recommends enhancements to ensure continued effectiveness of the Chemistry Control for Primary Systems Program.

RAI 3.3.11-A-1

For CVCS bolting in an air environment, Note B in LRA Table 3.3.2-10 identifies that the item is consistent with NUREG-1801 for component material, environment and aging effect, but the AMP takes some exceptions to NUREG-1801 AMP. LRA Table 3.3.2-10 references LRA item 3.1.1-26 in Table 3.1.1 and credits the inservice inspection program for managing cracking in CVCS bolting. LRA item 3.1.1-26 states that this item is not consistent with NUREG-1801 and page B-6 of the LRA states that the aging management reviews did not identify the need for the GALL XI.M18 bolting integrity AMP. NUREG-1339 (referenced in GALL AMP XI.M18) includes a condition that bolting degradation is resolved on the basis of a plant-specific bolting integrity program. Clarify if the credited inservice inspection program is different from the GALL bolting integrity program for managing cracking in CVCS piping and valve bolting in the RCPB. If there are differences, identify those specific differences to the GALL bolting integrity program and the basis for those differences. Describe the bolting practices used to preclude stress corrosion cracking such as the control of high strength bolting materials, lubricants, bolt stress and hardness testing. Also, clarify how a visual inspection of CVCS closure bolting in RCPB piping and valves is effective in detecting fine cracks or cracking in bolting where the entire bolting surfaces are not readily visible.

Dominion Response:

As identified in Appendix B2.0, the Millstone LRA did not include a specific Bolting Integrity Aging Management Program (AMP) description with comparison to NUREG 1801, XI.M18 "Bolting Integrity". However, due to NRC concerns related to how and where Millstone addressed degradation of bolting, Millstone has developed a specific Bolting Integrity AMP and is providing a supplement to the Millstone Units 2 and 3 LRAs as follows:

A.2.1.26 LRA Appendix A 'FSAR Supplement'

The *Bolting Integrity* Program corresponds to NUREG-1801, Section XI.M18, "Bolting Integrity". The program manages the aging effects of cracking, loss of material, and for ASME Class 1 bolting, loss of preload.

This is accomplished by establishing good bolting practices in accordance with EPRI NP-5067, *Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel, Volume 1: Large Bolt Manual, and Volume 2: Small Bolts and Threaded Fasteners* and EPRI TR-104213, *Bolted Joint Maintenance and Application Guide*. For ASME Class bolting, aging effects are additionally managed by the performance of inservice examinations in accordance with ASME Section XI, Subsections IWB, IWC, IWD, and IWF.

The engineering evaluations determine if a component needs to be repaired/replaced or is acceptable for continued operation until the next scheduled inspection. Corrective actions for conditions that are adverse to quality are

performed in accordance with the Corrective Action Program as part of the Quality Assurance Program. The corrective action process provides reasonable assurance that deficiencies adverse to quality are either promptly corrected or are evaluated to be acceptable.

LRA Appendix B Aging Management Programs

BOLTING INTEGRITY

The *Bolting Integrity* Program is an existing program that manages the aging effects of cracking, loss of material, and for ASME Class 1 bolting, loss of preload. The program includes the good bolting practices established for in scope threaded fasteners in plant procedures in accordance with recognized industry organizations such as EPRI and AISC. The program also includes the inservice inspection requirements established in accordance with ASME Section XI, Subsections IWB, IWC, IWD, and IWF for ASME Class bolting.

Millstone good bolting practices are established in accordance with plant procedures. These procedures include requirements for proper disassembling, inspecting, and assembling of connections with threaded fasteners. The general practices that are established in this procedure are based on EPRI NP-5067, *Good Bolting Practices, A Reference Manual for Nuclear Power Plant Maintenance Personnel, Volume 1: Large Bolt Manual, and Volume 2: Small Bolts and Threaded Fasteners* and EPRI TR-104213, *Bolted Joint Maintenance and Application Guide.*

NUREG-1801 Consistency

The Millstone *Bolting Integrity* Program is an existing program that is consistent with the aging management program described in Chapter XI of NUREG-1801, Section XI.M18, *Bolting Integrity* with the clarification and exceptions as described below:

As a clarification in comparison to NUREG-1801, Section XI.M18, Dominion identifies loss of preload as an aging effect requiring management for ASME Class 1 bolting only, as the operating temperatures for all other in scope bolted connections are well below the threshold temperature at which stress relaxation of pressure boundary bolting would occur.

Exceptions to NUREG-1801

Exception 1: Basis Documents Referenced in NUREG-1801 for Safety-Related Bolting Are Not Directly Referenced by Millstone Bolting Integrity Program.
NUREG-1801 Section XI.M18 states that the program relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, and industry recommendations, as delineated in EPRI NP-5769 (with exceptions as noted in NUREG-1339) for safety-related bolting.

The procedures for ensuring bolting integrity at Millstone identify inspection requirements and general practices for in scope bolting that are consistent with the bolting recommendations identified in Section XI.M18, but do not directly reference EPRI NP-5769 or NUREG-1339 as applicable source documents for these recommendations. However, these procedures do reference and incorporate the good bolting practices identified in EPRI NP-5067. EPRI NP-5769 and EPRI NP-5067 are very closely related documents that cross-reference one another and reference NUREG-1339. EPRI NP-5769, Section 8, *Good Bolting Practices* defers to EPRI NP-5067 for the identification of bolting practices associated with disassembly and assembly of bolted joints, and the methods for minimizing bolted joint problems such as leaks, vibration loosening, fatigue, and stress corrosion cracking. Because the recommendations of EPRI NP-5769 and EPRI NP-5067 are so closely related, a reference by NUREG-1801, Section XI.M18 to EPRI NP-5769, is essentially a reference to the interrelated recommendations contained in EPRI NP-5067.

Further, NUREG-1801, Section XI.M18 acknowledges EPRI NP-5769 for the identification of the applicable ASME requirements related to bolting integrity. However, as stated in EPRI NP-5769, this document has only compiled the applicable ASME Code examination requirements associated with bolting for the purpose of convenience and clarification, and does not attempt to change or extend these requirements. The Millstone Inservice Inspection requirements as described in the Millstone *Bolting Integrity* Aging Management Program address the necessary examination requirements for ASME Class bolting.

Program Elements Affected

- *Scope of Program*

  This program relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, and industry recommendations, as delineated in EPRI NP-5769 (with exceptions as noted in NUREG-1339) for safety-related bolting.

  The procedures for ensuring bolting integrity at Millstone identify inspection requirements and general practices for bolting that are consistent with the bolting recommendations identified in Section XI.M18, but do not directly reference EPRI NP-5769 or NUREG-1339 as applicable source documents for

these recommendations. However, these procedures do reference and incorporate the good bolting practices identified in EPRI NP-5067. EPRI NP-5067 and EPRI NP-5769 are very closely related documents that cross-reference one another and reference NUREG-1339. EPRI NP-5769, Section 8, *Good Bolting Practices* defers to EPRI NP-5067 for the identification of bolting practices associated with disassembly and assembly of bolted joints, and the methods for minimizing bolted joint problems such as leaks, vibration loosening, fatigue, and stress corrosion cracking. Because the recommendations of EPRI NP-5769 and EPRI NP-5067 are so closely related, a reference by NUREG-1801, Section XI.M18 to EPRI NP-5769, is essentially a reference to the interrelated recommendations contained in EPRI NP-5067. Further, NUREG-1801, Section XI.M18 acknowledges EPRI NP-5769 for the identification of the applicable ASME requirements related to bolting integrity. However, as stated in EPRI NP-5769, this document has only compiled the applicable ASME Code examination requirements associated with bolting for the purpose of convenience and clarification, and does not attempt to change or extend these requirements. The Millstone Inservice Inspection requirements as described in Millstone *Bolting Integrity* Aging Management Program address the necessary examination requirements for ASME Class bolting.

- *Preventive Actions*

This program element identifies that selection of lubricants and sealants is in accordance with EPRI NP-5769 and the additional recommendations of NUREG-1339 to prevent or mitigate degradation and failure of safety-related bolting. (NUREG-1339 takes exception to certain items in EPRI NP-5769.)

The procedure for ensuring bolting integrity at Millstone identifies general practices for threaded fasteners, and conforms to the details identified in Section XI.M18, but does not directly reference EPRI NP-5769 as an applicable source document for industry recommendations. However, this procedure does reference and incorporate the good bolting practices identified in EPRI NP-5067, including recommendations for the selection of lubricants. This procedure addresses the proper cleaning of threaded fasteners prior to inspection, using only approved cleaners and solvents. The procedure also addresses the application of approved anti-seize compounds.

- *Detection of Aging Effects*

  This program element identifies that the inspection requirements [for ASME Class bolting] include the recommendations of EPRI NP-5769.

  EPRI NP-5769 has only compiled the applicable ASME Section XI Code examination requirements associated with bolting for the purpose of convenience and clarification, and does not attempt to change or extend these requirements. The Millstone Inservice Inspection requirements, as described in Millstone *Bolting Integrity* Aging Management Program, address the necessary examination requirements for ASME Class bolting.

- *Corrective Actions*

  This program element identifies that the repair and replacement requirements [for ASME Class Bolting] are in conformance with the recommendations of EPRI NP-5769.

  EPRI NP-5769 has only compiled the applicable ASME Section XI Code examination requirements associated with bolting for the purpose of convenience and clarification, and does not attempt to change or extend these requirements. The Millstone Inservice Inspection Plans, as described in the Millstone *Bolting Integrity* Aging Management Program, address the necessary repair and replacement requirements for ASME Class bolting as defined by ASME Section XI.

Exception 2: Use of Different Code Year than Identified in NUREG-1801

NUREG-1801, Section XI.M18 identifies inservice inspection requirements in accordance with Table IWB-2500-1 and the 1995 Edition through the 1996 Addenda of ASME Section XI. The Millstone ISI Program is based on the 1989 Edition with no addenda. There are no differences between these code years with respect to examination requirements for ASME Class 1, 2, and 3 bolting and their support bolting.

<u>Program Elements Affected</u>

- *Detection of Aging Effects*

  NUREG-1801, Section XI.M18 identifies inservice inspection requirements in accordance with the 1995 Edition through the 1996 Addenda of ASME Section XI. The Millstone ISI Program is based on the 1989 Edition with no addenda. There are no differences between these code years with respect to examination requirements for ASME Class 1, 2, and 3 bolting and their support bolting.

Enhancements

The *Bolting Integrity* Program does not require enhancement to be consistent with the aging management program described in NUREG-1801, Chapter XI, Section M18, "Bolting Integrity".

Operating Experience

Operating experience indicates that the inspections, good bolting practices, and corrective action activities have successfully maintained the integrity of bolting within the scope of license renewal. Extensive operating experience and ASME Section XI inspection histories have indicated a minimal number of leaks at the reactor coolant pressure boundary and other in scope pressure retaining locations. Degradation of closure bolting, support bolting, and structural bolting that is found through these inspections is recorded and corrected as directed by engineering evaluation to maintain component intended functions.

In reviewing operating experience at Millstone Units 2 and 3, the following occurrences were noted and considered in evaluating the effectiveness of the program:

Support Does Not Meet Acceptance Criteria as Specified in Procedure

During performance of a VT-3 visual examination on Unit 2, the procedural acceptance criteria were not met for a support located on the suction piping to the turbine driven auxiliary feedwater pump. One anchor bolt did not have full thread engagement (i.e., one thread short of being flush). Design Engineering performed a walkdown and evaluated the support. The condition was determined to be acceptable as is. The anchor bolt was accepted based upon a referenced calculation. The analysis concluded that neither the structural integrity of the support nor the safety function of the suction piping for the turbine driven auxiliary feedwater pump were impacted.

Bolting for Containment Airlock Pillow Bearing Is Degraded

A mechanic observed that the bolting associated with the inner and outer door of the personnel airlock for Millstone Unit 2 was failing. The nuts for holding the pillow block bearing in place were being pulled into the bolthole, allowing the pillow block bearing to be pulled out of position. The pillow block bearing provides support for the upper portion of the door hinge pin, which allows the main upper bearing to support the weight of the door. An Engineering evaluation was performed and determined that the bolted configuration for the pillow block required repair. The bolting was replaced as part of this repair.

Diesel Engine Air Cooler Heat Exchanger Found to Have 4 Bolts Deteriorated

While repairing a service water leak on the end cover of the "B" diesel air cooler heat exchanger, the mechanic observed that four of the bolts were deteriorated. The System Engineer was contacted to aid in evaluating the condition. An Engineering evaluation was performed, which determined that the bolting had not failed but was sufficiently degraded such that replacement was warranted. All the bolting on the end cover was replaced.

Conclusion

The *Bolting Integrity* Program ensures that the effects of aging associated with the in-scope components will be adequately managed so that there is reasonable assurance that their intended functions will be maintained consistent with the current licensing basis throughout the period of extended operation.

RAI 3.3-A-1 (Units 2 & 3)

The LRA identifies a borated water leakage environment for various mechanical components in auxiliary systems. Both the boric acid corrosion program and general condition monitoring program are credited with managing loss of material from external surfaces of these components. The LRA states that the general condition monitoring program is performed in accessible plant areas. Clarify how loss of material is managed for auxiliary system components not normally visible, such as under insulation or in normally inaccessible areas. In addition, the LRA states that the boric acid corrosion program is consistent with NUREG-1801, Section XI.M10. The scope of NUREG-1801, Section XI.M10 is limited to components in the vicinity of the reactor coolant pressure boundary. However, it appears that the Millstone Units 2 and 3 boric acid corrosion program is credited with managing loss of material caused by borated water leakage in systems that may not be in the vicinity of the reactor coolant pressure boundary, such as the radwaste area ventilation system. Clarify this potential discrepancy. If the scope of the Millstone Units 2 and 3 boric acid corrosion program is different from the GALL XI.M10 program, the Millstone Units 2 and 3 program should be revised accordingly in the AMP and FSAR supplement descriptions. Also identify the basis for applying the boric acid corrosion program to manage boric acid corrosion in copper alloy and cast iron materials that are not addressed in GALL AMP XI.M10 and may require a different inspection frequency.

Dominion Response:

See RAI 3.4-1 for the response regarding the inspections for boric acid corrosion outside of containment.

Management of boric acid corrosion in copper alloy and cast iron materials is performed in the same manner as any other material since these materials are typically part of the equipment that is considered a boric acid target and the material type is considered when an engineering evaluation is performed. These material types in containment would be inspected as part of the boric acid leakage walkdown while the containment was open for refueling. Any boric acid leakage in containment during the operating cycle would be monitored and the plant shut down for repairs if the leakage exceeded predetermined limits. Inspection of any equipment (or materials) subject to the boric acid leakage would be performed and evaluated when the plant is shut down. For areas outside of containment, general equipment (or materials) inspections are performed as often as daily, which would identify any boric acid leakage and any required subsequent evaluation. Plant operating experience indicates that boric acid inspections performed once per refueling cycle are adequate to maintain the intended function of the equipment in containment. Plant and industry operating experience indicate that a boric acid leak that starts during the operating cycle does not damage the equipment to the point where it cannot perform its intended function prior to the next refueling outage.

An independent assessment was performed by INPO in August 2003. INPO noted that the auxiliary buildings for units 2 & 3 are clean and orderly, boric acid leaks are captured in the station corrective action program, and general materiel condition is good. Also, they noted that the computer based training module has raised the awareness of station employees with regard to the boric acid corrosion program requirements and the effect boric acid can have on systems, structures and components. Some minor program enhancements were recommended and are being addressed through the Corrective Action Program.

The following clarification will be added to the Unit 2 Appendix A "FSAR Supplement", Section A2.1.3, Boric Acid Corrosion, Program Description and the Unit 3 Appendix A "FSAR Supplement", Section A2.1.2, Boric Acid Corrosion, Program Description:

The Boric Acid Corrosion program provides both detection and analysis of leakage of borated water inside containment. The General Condition Monitoring program is the primary method for detecting borated water leakage outside containment. The analysis of the leakage is performed through the Boric Acid Corrosion program. Any necessary corrective actions are implemented through the Corrective Action Program.

RAI 3.3-B-1 (Units 2 & 3)

The LRA identifies a borated water leakage environment for various mechanical components in auxiliary systems. Both the boric acid corrosion program and general condition monitoring program are credited with managing loss of material from external surfaces of these components. The LRA states that the general condition monitoring program is performed in accessible plant areas. Clarify how loss of material is managed for auxiliary system components not normally visible, such as under insulation or in normally inaccessible areas. In addition, the LRA states that the boric acid corrosion program is consistent with NUREG-1801, Section XI.M10. The scope of NUREG-1801, Section XI.M10 is limited to components in the vicinity of the reactor coolant pressure boundary. However, it appears that the Millstone Units 2 and 3 boric acid corrosion program is credited with managing loss of material caused by borated water leakage in systems that may not be in the vicinity of the reactor coolant pressure boundary, such as the radwaste area ventilation system. Clarify this potential discrepancy. If the scope of the Millstone Units 2 and 3 boric acid corrosion program is different from the GALL XI.M10 program, the Millstone Units 2 and 3 program should be revised accordingly in the AMP and FSAR supplement descriptions. Also identify the basis for applying the boric acid corrosion program to manage boric acid corrosion in copper alloy and cast iron materials that are not addressed in GALL AMP XI.M10 and may require a different inspection frequency.

Dominion Response:

See the response to RAI 3.3-A-1.

RAI 3.5-2

In discussing item number 3.5.1-03 (Table 3.5.1) of the LRA, the applicant asserts that the Millstone AMR results are consistent with NUREG-1801. NUREG- 1801 under item A3.1 (page II A3.6) recommends further evaluation regarding the stress corrosion cracking of containment bellows. Table 3.5.2, under "Expansion Bellows" makes reference to the Table items 3.2.1-05 and 3.2.1-06. However, they do not address the expansion bellows associated with the containment pressure boundary. Normally, applicants take credit for properly designed Type B tests to ensure the leak tight behavior of the bellows. However, in AMP B2.1.6, the applicant does not take credit for Type B testing. The applicant is requested to provide additional information regarding the containment pressure boundary bellows at Millstone 2 and 3, relevant operating experience, and method(s) used to detect their age related degradation.

Dominion Response:

As identified in the response to RAI 3.5-1, Dominion will credit Local Leak Rate Tests in accordance with 10CFR50 Appendix J requirements for Type B penetrations.

Both Millstone Units 2 and 3 have bellows type penetrations associated with the design of their respective fuel transfer tubes. These are the only examples of bellows type penetrations for either unit. The Millstone Unit 2 bellows type penetration does not form any portion of the Containment pressure boundary, and therefore, does not require leak rate testing in accordance with Appendix J requirements. Millstone Unit 3 includes the bellows type penetration for the fuel transfer tube in its Appendix J Program as a Type B containment penetration. In accordance with Appendix J requirements, each time a Type B penetration has been opened, it must have a Type B test performed after closure to re-establish the containment boundary integrity. As such, this bellows type penetration is Local Leak Rate Tested during each refueling outage after completion of refueling activities and after the penetration flange has been reinstalled and verified as leak tight to establish the containment boundary.

RAI 3.5-3 (Unit 3)

In item number 3.5.1-08, the applicant asserts that settlement is not expected to occur during the period of extended operation. Further evaluation provided in Subsection 3.5.2.2.1.2 indicates that the containment and part of the engineering safety feature building foundation mats are sitting on porous concrete foundation. During years 1996-1997, it was revealed that drainage water through the porous foundation consisted of significant amount of high alumina cement, and that the applicant was monitoring depletion of cement and settlement of the affected structures (see NRC Info Notice 97-11). The applicant is requested to provide a summary of the quantitative assessment of the depletion of cement and its affects on the settlement of the structures during the period of extended operation. Also, the applicant is requested to justify why this item should not require a TLAA.

Dominion Response:

Settlement of the Millstone Unit 3 containment structure is not considered a TLAA. This analysis does not involve time-limited assumptions since even assuming the worst case situation represented by a complete loss of all concrete in the porous concrete subfoundation, the resultant change in frequency characteristics are within the uncertainty range allowed for the peak broadened spectra used in the design of the containment structure (M. H. Brothers to NRC, *Millstone Power Station Unit No. 3 – Response to Request for Additional Information on Erosion of Cement from the Underlying Porous Concrete Drainage System, Millstone Unit No. 3*, Letter B16403 dated April 30, 1997).

Millstone Unit 3 has performed extensive analysis of the condition of the porous concrete subfoundation, including the effect of cement erosion, the potential loss of strength of the subfoundation due to conversion of the high alumina cement, the effect of cement erosion on the load bearing capacity of the porous concrete, and the functional integrity of the containment structure (J. A. Price to NRC, *Millstone Power Station Unit No. 3 License Renewal – Request for Exemption From the Requirements of 10 CFR 54.17(c), Response to Request for Additional Information*, Letter B18948 dated September 3, 2003). The mass-loss of high alumina (calcium-alumina) residue discharged into the ESF sumps has been monitored since the startup of Millstone Unit 3 in 1986. A commitment (captured in the Structures Monitoring Program) to continue this periodic monitoring was made as a means of insuring that no new or adverse changes are occurring in the porous concrete subfoundation (M. L. Bowling to NRC, *Millstone Nuclear Power Station Unit 3, Response to Request for Additional Information – Erosion of Cement From the Underlying Porous Concrete Drainage System*, Letter B17115 dated April 16, 1998). ESF sump sample results can be found in Table 1. These results are conservatively projected to year 2026 (480 months) in Figure 1. The 480 months represents the current 40-year license x 12 months/year. By 2026 approximately 3,600 pounds (or 0.5%) of the 670,000 pounds of calcium-alumina cement in the porous media could be lost. This loss is not expected to adversely affect the function of the porous media (NRC to M. L. Bowling, *NRC Combined*

Inspection 50-245/98-208; 50-336/98-208; 50-423/98-208 and Notice of Violation, Letter A13866 dated August 12, 1998).

Construction Technology Laboratories and Altran Corporation performed a settlement estimate based on testing of extracted basemat core samples and extensive chemical and physical evaluations. The porous concrete was found to be in good condition after 23 years of exposure, exhibiting a compression strength on the order of 2,700-3,000 psi with negligible displacement. The maximum displacement is less than 0.002 inches for the limiting design basis loading (215 psi) case (J. P. McElwain to NRC, *Millstone Power Station Unit No. 3 – Response to Request for Additional Information on Erosion of Cement from the Underlying Porous Concrete Drainage System*, Letter B16925 dated December 19, 1997).

In support of this assessment, a number of bounding evaluations were performed and safety factors were identified. Detailed results are presented in letter: NRC to M. L. Bowling, *NRC Combined Inspection 50-245/98-208; 50-336/98-208; 50-423/98-208 and Notice of Violation*, A13866 dated August 12, 1998. A summary of these results is presented in the following paragraphs.

An assumption was made that the porous concrete layer within the Millstone Unit 3 containment basemat could crush more than 2% under a 650 psi plane strain loading when subject to an SSE or accident pressure loading. This crushing could lead to an unacceptable settlement of the containment building. The assumed 650 psi loading provides for a safety factor of 3 (650 psi/215 psi) against crushing of the porous concrete layer. This information in conjunction with actual core sample results demonstrates that the imposed bearing stress on the porous concrete would have to reach 5,000 psi or greater before a 2% crushing of the porous concrete layer would become a concern. This result represents a safety factor of greater than 20 (5,000 psi/215 psi) against undesirable containment settlement.

Four additional evaluations were performed. These evaluations addressed (1) uplift of the containment under SSE combined with the maximum hydrostatic head, (2) loss of integrity of the porous concrete around the peripheral drain pipe, (3) loss of porous concrete integrity around the two interior drain pipes, and (4) a loss of porous concrete integrity in five circular areas with a diameter of 5-feet each (in the vicinity of the drain pipe intersection) together with an assumption that the drainage pipes are filled with the cement eroded from the porous concrete. In evaluation (1), a safety factor of 1.5 was identified against uplift of the containment. For evaluations (2, 3 and 4), which addressed cement loss, loss of foundation load bearing area, and the ability of the 10-foot thick basemat to span the degraded areas of the porous concrete, the containment structure was found to be operable, fully qualified and able to perform its intended safety function. Specifically, the design basis for the Millstone Unit 3 containment mat is satisfied for strength, stiffness and settlement for the current licensing period and beyond.

Based upon these evaluations and the commitments identified in Table 2, the Millstone Unit 3 containment is expected to perform its safety function through the period of extended operation.

Results of a detailed NRC inspection of the Millstone Unit 3 porous concrete analyses are documented in a letter to Northeast Nuclear Energy Company (NRC to M. L. Bowling, *NRC Combined Inspection 50-245/98-208; 50-336/98-208; 50-423/98-208 and Notice of Violation*, Letter A13866 dated August 12, 1998). As a result of this inspection, the NRC staff concluded "...the erosion of cement from the underlying porous [concrete] drainage system has not jeopardized the [Unit 3] containment's ability to perform its safety function for the immediate future. Moreover, through an in-depth evaluation of the present and future potential degradation of the porous concrete media, [Millstone Unit No. 3] demonstrated that the containment structure will maintain its ability to perform the intended functions through the licensed lifetime of the plant (until year 2026), and beyond."

Table 1
Millstone Unit 3
Mass-Loss of Calcium-Alumina
ESF Sumps

Sampling Period	Sampling Period (months)	Nominal Loss of Calcium-Alumina (lbs/month)$^{(4)}$	Nominal Loss thru Sampling Period (lbs)$^{(4)}$	Cumulative Loss (lbs)$^{(4)}$
1987 thru 1994	84	7.89	661	661
01/1995 thru 07/1996	19	8.21	156	817
08/1996 thru 01/1997	6	20.00$^{(1)}$	120$^{(1)}$	937
02/1997 thru 12/1997	11	5.63	62	999
01/1998 thru 12/1998	12	8.58	103	1102
01/1999 thru 06/1999	6	8.00	48	1150
07/1999 thru 04/2000	10	6.60	66	1216
05/2000 thru 03/2001	11	6.81	75	1291
04/2001 thru 09/2001	6	3.83$^{(2)}$	23$^{(2)}$	1314
10/2001 thru 04/2002	7	6.35	44.5	1358.5
05/2002 thru 02/2003	10	4.95	49.5	1408
03/2003 thru 03/2004	13	5.23	68	1476
04/2004 thru Present	TBD$^{(3)}$	TBD$^{(3)}$	TBD$^{(3)}$	TDB$^{(3)}$

(1) Considered a non-representative result. Includes sediment from other sump locations.
(2) Considered a non-representative result. First result following hardware modifications.
(3) To Be Determined
(4) Dry weight.

Table 2
Millstone Unit 3
Containment Basemat Commitments Made in Previous Correspondence

Number	Commitment	Status
B16298-1	Perform a study of test samples associated with Millstone Unit 3 porous concrete to better understand the degradation mechanism(1)	Completed(1)
B16566-1	Address in Unit 3's final assessment the potential effect of conversion during placement on high alumina cement (HAC) porous concrete degradation(2)	Completed(3)
B16566-2	Perform HAC core samples in the ESF sump area base slab and test water environments to provide a more accurate assessment of the current condition of the HAC(2)	Completed(3)
B16566-3	Address in the final assessment the consequences of potential strength loss in the HAC porous concrete layer(2)	Completed(3)
B16566-4	Address in the final assessment the actual consequences of maximum expected differential settlement(2)	Completed(3)
B16566-5	Submit an amendment request for the Millstone Unit 3 Technical Specifications to include the limits and frequency for measuring the maximum Containment Building settlement (total), differential settlement (tilt) and penetration differential settlement(2)	Retracted(7)
B17131-01	Discussion of planned monitoring of future conditions of the containment basemat structure will be included by NNECO in a response to a more recent request for information from the NRC Staff, February 24, 1998(4)	Completed(5)
B17115-01	Monitoring of the HAC porous concrete and portland cement porous concrete groundwater chemistry to confirm the sub-containment chemical and environmental conditions(5, 6)	Yearly(5, 6, 8)

Number	Commitment	Status
B17115-02	Measuring of the white residue/mass-loss of calcium-alumina in the ESF sumps(5, 6)	Semi-annually(5, 6, 8)
B17115-03	Inspection of the sub-containment drainage piping in the ESF sumps(5, 6)	Yearly(5, 6, 8)
B17115-04	Containment structure settlement monitoring(5, 6)	External surveys every 2 years; internal ISI every 3 years(5, 6, 8)

(1) M. H. Brothers to NRC, *Millstone Nuclear Power Station No. 3 – Evaluation of Phase III Containment Basemat Mock-up Testing Report Millstone Unit No. 3*, Letter B16298 dated February 28, 1997.

(2) J. P. McElwain to NRC, *Millstone Nuclear Power Station No. 3 –Response to Request for Additional Information on Erosion of Cement from the Underlying Porous Concrete Drainage System*, Letter B16566 dated July 16, 1997.

(3) J. P. McElwain to NRC, *Millstone Nuclear Power Station No. 3 –Response to Request for Additional Information on Erosion of Cement from the Underlying Porous Concrete Drainage System*, Letter 16925 dated December 19, 1997.

(4) M. L. Bowling to NRC, *Millstone Nuclear Power Station No. 3 – Notification of Revised Commitment Regarding Erosion of Cement from the Underlying Porous Concrete Drainage System (TAC No. M96402)*, Letter B17131 dated March 30, 1998.

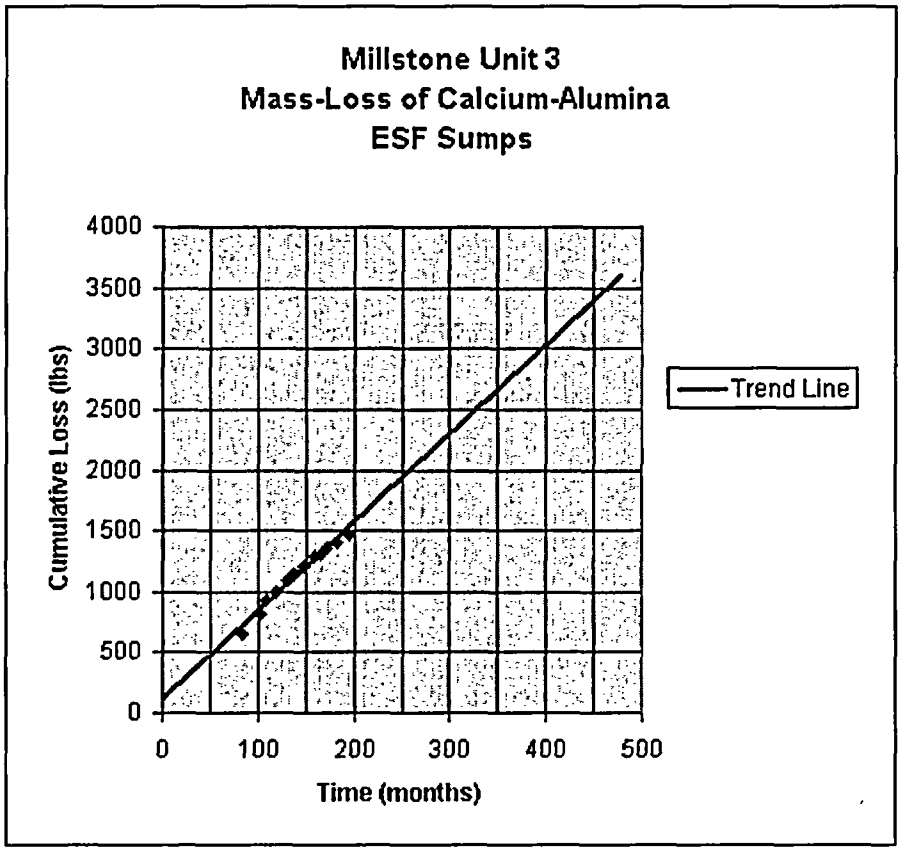
(5) M. L. Bowling to NRC, *Millstone Nuclear Power Station No. 3 – Clarification of Commitments-Erosion of Cement from the Underlying Porous Concrete Drainage System*, Letter B17206 dated April 27, 1998.

(6) M. L. Bowling to NRC, *Millstone Nuclear Power Station No. 3 – Response to Request for Additional Information-Erosion of Cement from the Underlying Porous Concrete Drainage System*, Letter B17115 dated April 16, 1998.

(7) M. L. Bowling to NRC, *Millstone Nuclear Power Station No. 3 – Notification of Revised Commitment Regarding Erosion of Cement from the Underlying Porous Concrete Drainage System (TAC No. M96402)*, Letter B17131 dated March 30, 1998.

(8) NRC to M. L. Bowling, *NRC Combined Inspection 50-245/98-208; 50-336/98-208; 50-423/98-208 and Notice of Violation*, Letter A13866 dated August 12, 1998.

Figure 1
Millstone Unit 3
Mass-Loss of Calcium-Alumina
ESF Sumps



RAI 3.5-14 (Units 2 & 3)

In discussion of Item 3.5.1-12 in Section 3.5.2.2.1.4, the applicant notes that the moisture barrier is monitored under containment inspection program for aging degradation. The industry experience indicates that the moisture barrier degrades with time, and any moisture accumulation in the degraded barrier corrodes the steel liner. The applicant is requested to provide information regarding the operating experience related to the degradation of moisture barrier and the containment liner plate at Millstone 2 and 3. The applicant is requested to include a discussion of acceptable liner plate corrosion before it is reinstated to the nominal thickness.

Dominion Response:

The Containment ISI Program conforms to ASME XI Subsection IWE (1998 Edition) for monitoring the effects of aging associated with both the moisture barrier and the steel liner. The inspection of moisture barriers is intended to prevent undetected intrusion of moisture to inaccessible areas of the pressure retaining liner. Subsection IWE identifies the moisture barrier examination method (visual), and the examination extent and frequency (100% each inspection period). By Subsection IWE requirements, the acceptance standards are "owner defined". Millstone Units 2 and 3 have defined the general and detailed visual acceptance criteria in plant specific procedures. For augmented examinations of the liner that involve Ultrasonic Testing (UT), ASME Section XI, Subparagraph IWE-3511.3 requires that loss of material in a local area projected to exceed 10% of the nominal wall thickness prior to the next examination shall be documented. Such areas are entered into the Corrective Action Program and either accepted by engineering evaluation or corrected by performance of repair/replacement activities.

For Millstone Units 2 and 3, various examples of Operating Experience associated with the moisture barrier and the liner (such as the results of baseline examinations performed under the Containment ISI Program) are available for review at the station. The extent of the visual examinations and the necessity of additional volumetric examinations have been as specified in the IWE Inspection Schedule. Examples of Containment operating experience for Millstone Units 2 and 3 are provided in the License Renewal Application Appendix B (Section B2.1.16).

<u>Millstone Unit 2</u>

The moisture barrier for the Unit 2 Containment liner was inspected in 2000 as part of the ASME Section XI, Subsection IWE examinations. The inspection revealed indications, which upon evaluation required that the moisture barrier material be removed, a detailed IWE examination of the liner be performed, the liner be recoated, and the moisture barrier be replaced. The work scope was completed in two phases, approximately 50% of the locations in outage 2R13 and the remainder in outage 2R15. During the examination, some pitting of the liner was observed and determined to be acceptable by engineering evaluation and

calculation review. The condition of the Unit 2 liner was determined by Engineering to meet the requirements of Subsection IWE of ASME Section XI and acceptable for continued service.

Millstone Unit 3

In 2000 the moisture barrier for the Unit 3 Containment liner was inspected as part of the ASME Section XI, Subsection IWE examinations. The inspection revealed unacceptable results where, for specific areas, the moisture barrier had not been installed. These areas were documented and repaired in accordance with Subsection IWE requirements. Detailed visual examinations of the moisture barrier are performed as directed by IWE requirements and the Millstone Containment ISI Program. The liner surface for the depth of the exposed joint was acceptable and required no further supplemental examination.

Containment Liner UT Inspections

The following are specific examples of Ultrasonic testing (UT) performed to measure the thickness of the Containment liners at Millstone Units 2 and 3, respectively, and support the above Operating Experience for the liners:

Millstone Unit 2

April 26, 2000:

Visual examination of the inside surface of the Containment liner on April 26, 2000 revealed some minor pits along the perimeter of the liner at the moisture barrier seal [elevation (-) 22'-6", location azimuths 22.5, 97.5, 172.5, 187.5, and 217.5 degrees]. UT examinations of these areas revealed that the liner wall thickness was below the ASME Section XI, Subsection IWE acceptance standards. UT examinations were performed on May 5, 2000 in accordance with AWO M2-00-08846. An Engineering review confirmed that the corrosion was from wetting of the liner surface, and the result of moisture intrusion through the degraded moisture barrier seal.

The UT examinations were performed at excavated regions behind the moisture barrier that are below the Containment floor grade. Only one location azimuth (97.5 degrees) could be measured. The lowest reading obtained at this location was 0.216 inches. Visual inspections of the remaining four areas indicated similar levels of corrosion; therefore, this level of degradation was assumed to exist randomly throughout the excavated regions for the areas being examined. The UT examination resulted in a measured liner wall thickness of 0.216 inches. The design nominal thickness of the liner is 0.250 inches. In accordance with ASME Section XI, Subparagraph IWE 3122.3, the local areas that exceed 10% of the nominal wall thickness prior to the next examination shall be either accepted by engineering evaluation or corrected by performance of repair/replacement activities. The measured liner wall thickness of 0.216 inches exceeded the minimum nominal wall

thickness allowed for the liner of 0.225 inches (for 10% wall loss), and therefore, needed to be entered into the Corrective Action Program as required by ASME Section XI. A calculation was performed, which determined that the Containment liner design function would be maintained with a minimum wall thickness of 0.0625 inches; therefore, the as found condition was acceptable as is.

May 5, 2000:

Visual examination of the Containment liner revealed signs of corrosion (approximately 4 inches in diameter) on the inside surface of the liner at elevation (-) 22'-6", location azimuth 92 degrees (12 feet above floor level). Ultrasonic testing (UT) was performed on May 5, 2000. An Engineering review was performed, which confirmed that the corrosion was the result of wetting of the liner surface. The review concluded that the wetting had not resulted in a significant loss of base metal.

Specifically, the UT examination results indicated that the area in question had a liner wall thickness of 0.239 inches. The design nominal thickness of the liner is 0.250 inches. In accordance with ASME Section XI, Subparagraph IWE 3122.3, local areas exhibiting less than 10% wall loss are acceptable for continued service. The reading of 0.239 inches was greater than the 0.225 inches minimum wall thickness allowable (for 10 % wall loss), and therefore, met the acceptance standards of ASME Section XI.

May 12, 2000:

Visual examination on the inside of the Containment liner at elevation (-) 22'-6" revealed signs of corrosion at location azimuth 180 degrees, approximately 16 feet above floor level on the underside of the fuel transfer canal. UT inspection was performed on May 12, 2000. An Engineering review confirmed that the corrosion was from wetting of the liner surface, and the result of condensation forming within the containment.

The results indicated that the area in question had a liner minimum wall thickness of 0.275 inches. The design nominal thickness of the liner is 0.250 inches. In accordance with ASME Section XI, Subparagraph IWE 3122.3, local areas that exhibit less than 10% wall loss are acceptable for continued service. The reading of 0.275 inches was greater than the nominal wall thickness of 0.250 inches, and therefore, met the acceptance standards of ASME Section XI.

March 15, 2002:

UT examinations were performed on March 15, 2002 for the underside of the fuel transfer canal, 16 feet above the Containment floor [elevation (-) 22'-6", location azimuth 180 degrees]. The results indicated that the area in question had a minimum liner wall thickness of 0.272 inches. The design nominal thickness of the liner is 0.250 inches. In accordance with ASME Section XI, Subparagraph IWE 3122.3, local areas that exhibit

less than 10% wall loss are acceptable for continued service. The reading of 0.275 inches was greater than the nominal wall thickness of 0.250 inches, and therefore, met the acceptance standards of ASME Section XI.

November 5, 2003:

Visual examination of the liner at the moisture barrier seal [elevation (-) 22'-6"] revealed signs of corrosion behind and below the seal. On November 5, 2003, UT examinations were performed for the corroded areas (at location azimuths 30, 95, 250, and 280 degrees). These UT examinations revealed that the liner thickness was below the ASME Section XI, Subsection IWE acceptance standards. The results indicated liner thicknesses of 0.247 inches at 30 degrees, 0.208 inches at 95 degrees, 0.206 inches at 250 degrees, and 0.198 inches at 280 degrees.

The design nominal thickness of the liner is 0.250 inches. In accordance with ASME Section XI, Subparagraph IWE 3122.3, the local areas that exceed 10% of the nominal wall thickness prior to the next examination shall be either accepted by engineering evaluation or corrected by performance of repair/replacement activities. Three of the four examined locations met this criterion. The measured liner wall thickness of 0.198 inches exceeded the minimum nominal wall thickness allowed for the liner of 0.225 inches (for 10 % wall loss), and therefore, needed to be entered into the Corrective Action Program as required by ASME Section XI. Engineering evaluated the condition, and determined that the Containment liner design function was maintained with a minimum wall thickness of 0.0625 inches; therefore, the as found condition was acceptable as is.

Millstone Unit 3

February 19, 2001:

In accordance with Engineering direction, a detailed visual examination and UT examinations were performed on February 19, 2001 for a 12-inch area of the Containment liner where the moisture barrier had been removed [elevation (-) 24'-6", between column lines 21 and 1]. Based on the visual examination results and the UT readings that were obtained (0.375 inches of wall thickness or greater), the area was determined to be acceptable for continued service once the area was properly cleaned and resealed. The moisture barrier was designated as a Category E-C area requiring detailed examinations for future inspections as prescribed by ASME Section XI, Subsection IWE requirements.

RAI 3.5-16

Tables 3.5.2-2 of Units 2 and 3 are related to the aging management of the enclosure buildings surrounding the containments. For Unit 2, the applicant has incorporated the aging management of blow-off panels. This is not the case for Unit 3. The applicant is requested to discuss the reasons for the difference.

Dominion Response:

The main steam lines for Millstone Unit 2 go through the enclosure building, and the potential exists for excessive pressure to build-up inside this building during a main steam line leak. For this reason blow-off panels were incorporated into the Unit 2 enclosure building design, and the aging management of these blow-off panels has been included for License Renewal.

The main steam lines for Millstone Unit 3 go through the main steam valve building, and not the enclosure building. For this reason blow-off panels are installed in the main steam valve building, and the aging management of these blow-off panels has been included for License Renewal. Because the main steam lines for Millstone Unit 3 do not go through the enclosure building, the potential for excessive pressure to build-up inside this building does not exist, and blow-off panels were not installed.

RAI 3.6-2 (Units 2 & 3)

The applicant stated that the SBO recovery path was in the scope of LR and as described in Section 2.1.3.7.5 of the LRA. Please describe the justification as to why an aging management program was not included for the high voltage cables and connectors from the 345 kV switchyard to the RSST and the medium voltage cables (including any cable bus or bus duct) and connectors from the RSST to the Class 1E switchgear.

Dominion Response:

The aging management review results for cables and connectors are presented in LRA Table 3.6.2-1 and for the bus ducts are presented in Table 3.6.2-3.

The high-voltage lines from the 345 kV switchyard to the RSST for both Millstone Units 2 and 3 consist of aluminum conductor steel reinforced (ACSR) bare transmission conductors and metal bus duct. Industry experience has shown that the corrosion of ACSR conductors is a slow acting aging effect that is not a concern for the period of extended operation. As a result, there are no aging effects requiring management for metal conductors in the atmosphere/weather environment as indicated in Table 3.6.2-1. Additionally, there are no aging effects indicated in Table 3.6.2-3 for the metal bus ducts since the aluminum tubular bus in the Millstone switchyard environment has shown no aging effects that could cause a loss of intended function. Therefore, there is no requirement for an aging management program for these components.

The medium voltage cables from the Unit 2 RSST to the Class 1E switchgear consist of metal conductors with organic insulation and are included in the commodity groups "Conductors" and "Insulation (Except Sensitive Instrumentation Circuits and Medium Voltage Inaccessible Cables Exposed to Moisture)", respectively, in LRA Table 3.6.2-1. The conductors associated with these cables are covered with insulation except at connection points, which are enclosed in termination boxes or covered with heat shrink sleeves. Therefore, there is no corrosive environment present that could result in aging effects and there is no requirement for an aging management program. The insulation for these cables is subject to cracking and embrittlement aging effects and is managed for the effects of aging with the Electrical Cables and Connectors not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP as indicated in Table 3.6.2-1. There are no bus ducts located between the RSST and the Class 1E switchgear in Unit 2.

The medium voltage cables from the Unit 3 RSST to the Class 1E switchgear consist of metal conductors included in the commodity group "Conductors" and organic insulation included in the commodity groups "Insulation (Medium Voltage Inaccessible Cables Exposed to Moisture)" and "Insulation (Except Sensitive Instrumentation Circuits and Medium Voltage Inaccessible Cables Exposed to Moisture)" in LRA Table 3.6.2-1. The conductors associated with these cables are covered with insulation except at connection points, which are enclosed in termination boxes or covered with heat shrink sleeves.

Therefore, there is no corrosive environment present that could result in aging effects and there is no requirement for an aging management program. Portions of the cable runs are routed below grade and have the potential for submergence in water. The insulation for these cables is in the commodity group "Insulation (Medium Voltage Inaccessible Cables Exposed to Moisture)" and is considered susceptible to the aging effect of water treeing. This aging effect is managed with the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP, as indicated in Table 3.6.2-1. The insulation for other portions of the cable runs is subject to cracking and embrittlement aging effects and is managed for the effects of aging with the Electrical Cables and Connectors not Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP.

There are non-segregated bus ducts in the SBO recovery path between the RSST and the Class 1E switchgear. Round, aluminum bus ducts are located outdoors between the RSST low-side cables and the building wall penetration. These bus ducts are all-welded, non-vented construction with no joints or fasteners. The conductor is bare, welded aluminum bus bar with no splices or fasteners. Inside the Service Building, bus duct runs are located at the 6.9kV and 4.16kV switchgear. These bus ducts are rectangular sections bolted together, with spliced and bolted insulated aluminum bus bar. The bus ducts are vented by means of down-turned elbow fittings mounted to the side of the duct at approximately eight to ten foot intervals with screened openings.

The operating experience contained in NRC Information Notices (IN) 89-64, 98-36, and 2000-14 was reviewed as part of the aging management review for these bus ducts. These INs identify aging issues related to degradation of conductor insulation due to debris and/or moisture accumulation, torque relaxation of conductor splice bolting due to thermal cycling, and corrosion of bus bar/splice plates due to inadequate silver-plating of the splice plate.

As described above, the bus duct in the SBO recovery path between the RSST and the Class 1E switchgear located outdoors consists of a non-vented, welded enclosure such that moisture or debris intrusion is not a concern. In addition, the solid, bare conductor is welded and there are no splice plates or bolting. Therefore, this operating experience is not applicable to the outdoor section of bus duct.

The remaining bus ducts are located indoors in an air-conditioned environment and vent openings are down-turned such that there is no concern for moisture or debris accumulation on the inside of the bus duct or conductor insulation. Without moisture or debris inside the duct, the bus bar insulation is not expected to degrade in a manner similar to that described in the INs. The 6.9kV bus ducts are normally energized but not loaded and the 4.16kV bus ducts are normally loaded to approximately 30% of rating (67% of rating when the RSST is supplying power). These busses are continuously energized/loaded such that thermal cycles are minimal and splice bolting torque relaxation is not expected to occur. In addition, with the relatively low operating current (related to rated capacity), degradation of splice boots or silver-plating such as that cited in IN 2000-14 is not expected. Therefore, it was concluded that the operating experience described in the INs is not applicable to these bus ducts.

The aging management review for the bus ducts in the SBO recovery path concluded that there are no applicable aging effects, as indicated in LRA Table 3.6.2-3, and no aging management program is required.

RAI 4.2.1-1

Regarding the Millstone Unit 2 reactor vessel neutron fluence calculations for 54 EFPY indicated in Section 4.2.1 and the corresponding fluence values in Table 4.2-1 of the LRA, the staff request the applicant to provide the following information:

a) What cross-section file is BUGLE-80 based on?

b) Does the methodology used in the fluence calculations conform to the guidance in Regulatory Guide (RG) 1.190?

c) How were the neutron sources derived?

d) What assumptions were made for the core loading (and thus the neutron sources) for the remainder of the current licensing period and the extended licensing period.

e) Was the presence of Pu in the outer assemblies and its effects on source strength and energy spectrum accounted for in the calculations?

Dominion Response:

a) The Bugle–80 package contains microscopic coupled (47-neutron, 20-gamma group) data. Fluence calculations employed an angular quadrature of 48 sectors (S8) and a third-order LeGendre polynomial scattering approximation (P3) cross-section library developed at Oak Ridge National Laboratory. The library was generated by collapse from DCL-41C/VITAMIN-C using a spectrum typical to that expected in a PWR shield (J. F. Opeka to NRC, *Millstone Nuclear Power Station, Unit No. 2 – Reactor Vessel Material Irradiation Surveillance Capsule W-104*, Letter B13971 dated November 27, 1991). The dosimeter reaction cross-sections are based on ENDF/B-IV evaluated data.

b) The methodology employed in the examination of this capsule does not fully conform to the guidance in Regulatory Guide 1.190. However, this methodology has been reviewed and accepted (NRC to J. F. Opeka, *Issuance of Amendment (TAC No. M86801)*, Letter A11431 dated January 27, 1994) resulting in the issuance of Millstone Unit 2 Technical Specification Amendment No. 170. The neutron fluence calculations for the Millstone Unit 2 reactor pressure vessel (Millstone Unit 2 LRA Section 4 – Tables 4.2-1 and 4.2-2) are based on Surveillance Capsule W-104 results (J. F. Opeka to NRC, *Millstone Nuclear Power Station, Unit No. 2 – Reactor Vessel Material Irradiation Surveillance Capsule W-104*, Letter B13971 dated November 27, 1991) using a two-dimensional discrete ordinates transport code DOTIV, version 4.3. Surveillance Capsule W-104 was removed for examination in 1990 following an exposure of 10 EFPY (S. E. Scace to NRC, *Millstone Nuclear Power Station, Unit No. 2 – Submittal of Third Reactor Vessel*

Surveillance Capsule Report, Letter B18847 dated February 26, 2003). Future capsule examinations will comply with Regulatory Guide 1.190 guidance.

c) The time-averaged space and energy dependent neutron source for Surveillance Capsule W-104 was calculated using the SORREL code developed by Framatome ANP. The effects of burnup on the spatial distribution of the neutron source was accounted for by calculating the cycle average fission spectrum for each fissile isotope on an assembly-by-assembly basis and by determining the cycle average specific neutron rate. This data was then used with the normalized time weighted average pin-by-pin relative power density distribution to determine the space and energy-dependent neutron source.

d) Projected 54 EFPY fluence values reflect fuel cycle specific calculations based on Surveillance Capsule W-104 results (J. F. Opeka to NRC, *Millstone Nuclear Power Station, Unit No. 2 – Reactor Vessel Material Irradiation Surveillance Capsule W-104*, Letter B13971 dated November 27, 1991.

e) Yes. The effects of burnup on the spatial distribution of the neutron source, including the use of depleted assemblies in the periphery (NRC to J. F. Opeka, *Issuance of Amendment (TAC No. M86801)*, Letter A11431 dated January 27, 1994), were accounted for by calculating the cycle average fission spectrum for each fissile isotope on an assembly-by-assembly basis and by determining the cycle average specific neutron emission rate. The isotopic fission spectrums for the ^{235}U, ^{238}U, ^{239}Pu, and ^{241}Pu isotopes were evaluated for Surveillance Capsule W-104.

RAI 4.2.1-2

Regarding the Millstone Unit 3 reactor vessel neutron fluence calculations for 54 EFPY indicated in Section 4.2.1 and the corresponding fluence values in Table 4.2-1 of the LRA, the staff request the applicant to provide the following information:

a) RG 1.190 was issued in March 2001. Confirm that the neutron fluence methodology adheres to this guidance.

b) What Code and approximations were used?

c) What cross-section file was used?

d) How were the neutron sources calculated and what assumptions were made regarding fuel loadings for the remainder of the current licensing period and the extended licensing period.

e) Was the presence of Pu in the outer assemblies and its effects on source strength and energy spectrum accounted for in the calculations?

Dominion Response:

a) The fast neutron fluence calculations for the Millstone Unit 3 reactor pressure vessel (Millstone Unit 3 LRA Section 4 – Table 4.2-1) were completed using a discrete-ordinates transport technique. The specific methodology applied to the calculation followed the guidance of Regulatory Guide 1.190.

b) All of the transport calculations were completed using the DORT discrete ordinates code, Version 3.1.

   Nominal design dimensions of the various structural components were used in developing the reactor geometry analytical models. Water temperatures and pressures, and associated coolant densities in the core, bypass, and downcomer regions were taken to be representative of full power operating conditions. The reactor core was treated as a homogeneous mixture of fuel, cladding, water, and miscellaneous core structures such as fuel assembly grids and guide tubes. In the transport models, spatial mesh sizes were chosen to assure that proper convergence of the inner iterations have been achieved on a pointwise basis.

c) The BUGLE-96 cross-section library was used. This library provides a 67 group coupled neutron-gamma ray cross-section data set produced specifically for light water reactor application. In the Millstone Unit 3 analysis, anisotropic scattering was treated with a P3 LeGendre expansion and the angular discretization was modeled with an S8 order of angular quadrature.

d) The neutron fluence determination was made on a Millstone Unit 3 specific basis. Presently, Millstone Unit 3 had completed six cycles of operation. The results of the fluence analysis reflect fuel cycle specific calculations for each of these completed cycles as well as projections for future operation extending to 54 EFPY. These fluence projections were based on the assumption that low leakage fuel management would continue and that the future fluence accumulation rate could be calculated using a core power distribution representative of the average of Cycles 4 through 6.

e) Yes. Energy and space dependent core power distributions were treated on a fuel cycle specific basis and included the effects of neutron fissioning in both uranium and plutonium isotopes. In applying this data, the fission spectra, neutrons released per fission, and energy released per fission accounted for the presence of both uranium (U) and plutonium (Pu) fissioning isotopes. Specifically, the burnup dependent effects on the neutron source accounted for the spatial variation of the magnitude of the source as well as for the spectral effects introduced by the distribution of the various fissioning isotopes (^{235}U, ^{238}U, ^{239}Pu, and ^{241}Pu).

RAI 4.2.1-3

The staff recognizes that the licensee calculated fluence values to 54 EFPYs (i.e., the end of the requested license extension) in Section 4.2.1 of the LRA, which contains the evaluations of TLAAs. However, the applicant did not specifically state that the calculations for neutron fluence values are TLAAs. The staff considers the calculations for neutron fluence values meets the requirements of 10 CFR 54.3, in that they use time limiting assumptions. Also, the operating assumptions in these calculations could change as for example with the introduction of new fuel, new material properties, etc. In such an instance 10 CFR 50.61 and other regulations requires recalculation of the fluence and reevaluation of the material properties. Pursuant to 10 CFR Part 54.21(d), the FSAR Supplement for a facility license renewal application (LRA) must contain a summary description for each aging management program and time-limited aging analysis proposed for management of the effects of aging. The staff has determined that Appendix A of the LRA (FSAR Supplement) did not include a corresponding FSAR Supplement summary description for the TLAA in Section 4.2.1, "Neutron Fluence," of the LRA. Therefore, it is necessary to capture this information in the FSAR Supplement. Pursuant to 10 CFR 54.21(d), the staff requires that a corresponding FSAR Supplement summary description for LRA Section 4.2.1 be included in the FSAR Supplement.

Dominion Response:

The following information will be added to the Millstone Unit 2 and Millstone Unit 3 LRA Appendix A "FSAR Supplement", Section A3.1.3, Pressure-Temperature Limits:

> "Millstone Unit [2] [3] will continue to calculate P-T limits based on fluence values developed in accordance with Regulatory Guide-1.190 requirements, as amended or superseded by future regulatory guidance changes, through the period of extended operation."

RAI 4.2.2-1

For Millstone, Unit 2, the NRC staff's Reactor Vessel Integrity Database (RVID) includes a weld, (upper/int. shell circ. welds 8-203, Heats 10137 and 33A277) that was not included in the Upper Shelf Energy (USE) evaluation in Table 4.2-1 of the LRA, and the Pressurized Thermal Shock (PTS) evaluation in Table 4.2-2 of the LRA. In your letter dated September 10, 1993, your response to Generic Letter 92-01, Revision 1, stated that this weld was fabricated using single wire feed welding with two different heats of weld wire. However, it could not be determined which weld wire was used on which section of the weld. Therefore, each weld wire will be independently evaluated during future delta RT_{NDT} and delta USE calculations and the worst case calculated value will become the controlling value for this weld. Based on this information provide USE and PTS evaluations for this weld which evaluate each candidate weld wire heat, or provide justification for not including it in the evaluation.

Dominion Response:

10 CFR 50 Appendix G provides a definition of the beltline region of the reactor pressure vessel as "the region of the reactor vessel (shell material including welds, heat affected zones, and plates or forgings) that directly surrounds the effective height of the active core and adjacent regions that are predicted to experience sufficient neutron radiation damage to be considered in the selection of the most limiting material with regard to radiation damage." The Millstone Unit 2 reactor pressure vessel upper to middle shell circumferential weld (weld No. 8-203) does not meet the Appendix G definition of beltline region and as such was not included in Millstone Unit 2 LRA Section 4 – Table 4.2-1 and Table 4.2-2. Specifically, weld No. 8-203 is above the active core.

An assessment has been performed to address an expansion of the Millstone Unit 2 reactor pressure vessel beltline region resulting from the period of extended operation. This assessment was used to evaluate all materials that were determined to reside within the 1.0×10^{17} n/cm^2 (E > 1.0 MeV) boundary. The results of this evaluation for weld No. 8-203 can be found in the following Tables 1 and 2. All materials and values identified in Millstone Unit 2 LRA Section 4 – Table 4.2-1 and Table 4.2-2 were found to remain bounding for the period of extended operation.

Table 1
Millstone Unit 2
RT_{PTS} Values at 54 EFPY

Material Description				Chemical Composition		Initial RT_{NDT} °F	Chemistry Factor °F	Inner Surface Fluence E18 n/cm^2	Margin °F	ΔRT_{PTS} °F	RT_{PTS} °F
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu Wt. %	Ni Wt. %						
Mid. Circ. Weld	8-203	33A277	Linde 0091	0.30	0.165	-56	143.4	2.43	65.5	88.4	97.9
Mid. Circ. Weld	8-203	10137	Linde 0091	0.23	0.043	-56	104.4	2.43	65.5	64.4	73.9

Table 2
Millstone Unit 2
Upper Shelf Energy Values at 54 EFPY

Material Description				Cu Wt. %	Initial USE Ft-lbs	Fluence 1/4t E18 n/cm^2	USE Ft-lbs	% Drop USE
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type					
Mid. Circumferential Weld	8-203	33A277	Linde 0091	0.30	101	1.45	72.2	28.5
Mid. Circumferential Weld	8-203	10137	Linde 0091	0.23	101	1.45	77.3	23.5

RAI 4.2.2-2

The upper shelf energy (USE) evaluation in Table 4.2-1 of the Millstone, Unit 2, application for the lower shell plate C-506-1, Heat C5667-1 provided a calculated percent drop in USE of 29.5% and an USE value of 76.1 ft-lbs. for 54 EFPY, which is consistent with position 1.1 of RG 1.99, Revision 2 for material that has no surveillance data available. RG 1.99, Revision 2 requires that all available plant-specific surveillance data be used in determining the USE. RVID shows that this plate has surveillance data available. Therefore, provide the calculated USE value for the lower shell plate C-506-1, Heat C5667-1 using all available surveillance data as required by RG 1.99, Revision 2.

Dominion Response:

The calculated USE values for the Millstone Unit 2 reactor pressure vessel lower shell plate C-506-1, heat number C5667-1, are provided in Table 1. This data was developed from surveillance capsule W-97 (W. G. Council to NRC, *Millstone Nuclear Power Station Unit No. 2 – Proposed Revisions to Technical Specifications Pressure-Temperature Limit Curves*, Letter B10990 dated January 4, 1984), surveillance capsule W-104 (J. F. Opeka to NRC, *Millstone Nuclear Power Station Unit No. 2 – Reactor Vessel Material Irradiation Surveillance Capsule W-104*, dated November 27, 1991), and surveillance capsule W-83 (S. E. Scace to NRC, *Millstone Nuclear Power Station No. 2 – Submittal of Third Reactor Vessel Surveillance Capsule Report*, Letter B18847 dated February 26, 2003) examination results. These values were developed by plotting the reduced surveillance capsule data on Figure 2 of Regulatory Guide 1.99, Revision 2, and fitting the points with a line drawn parallel to the existing Figure 2 lines. The initial USE value for heat number C5667-1 (Millstone Unit 2 LRA Section 4 – Table 4.2-1) is 108 Ft-lbs. The 54 EFPY fluence projection is based on the most recent surveillance capsule W-83 results.

Table 1
Millstone Unit 2
Calculated USE Values at 54 EFPY
Heat Number C5667-1

Surveillance Capsule	USE Ft-lbs	% Drop USE
W-97	54.5	49.5
W-104	68.0	37.0
W-83	68.6	36.5

RAI 4.2.2-3

Section 4.2.2 of the application for Millstone, Unit 2, states the following:

> *"There is a difference in the values presented in the application from RVID for the mid. circumferential welds fabricated with weld wire heats 90136 and 10137 and Linde 0091 flux. The value of the USE documented in Table 4.2-1 is 2.2 ft-lbs greater than the value provided in RVID. The Table 4.2-1 value is derived from surveillance weld material representative of this weld (same consumables) and constitutes a mean of all data at 100% shear."*

Provide all relevant surveillance weld material data for each of the weld wire heats (90136 and 10137) which were used to calculate the mean unirradiated USE values for each weld wire heat. If the weld data is not representative of each heat of weld wire, provide a generic value for this weld, such as those given in Combustion Engineering Owners Group report CEN-622-A.

Dominion Response:

The Millstone Unit 2 surveillance weld was fabricated (including use of the same consumables) to be representative of weld No. 9-203. A full Charpy curve is also available for this weld providing further information on initial materials properties. Based on available documentation and a review of Charpy testing performed on the unirradiated surveillance weld material, no distinction can be made between surveillance welds fabricated from heat numbers 90136 and 10137. The initial USE value of 132.2 ft-lbs (Millstone Unit 2 LRA Section 4 – Table 4.2-1) used for weld No. 9-203 (heat numbers 90136 and 10137) represents a mean value of all surveillance weld specimen impact energy results at 100% sheer (Table 1). This value is considered to be representative of weld No. 9-203.

Table 1
Millstone Unit 2
Charpy Impact Test Results

Specimen No.	Test Temp (°F)	Impact Energy (ft-lbs)	Lateral Expansion (mils)	Sheer (%)
36C	80	131.5	96	100
34Y	120	129.5	92	100
33T	120	132.5	92	100
356	160	127.0	91	100
31K	160	140.5	96	100
Mean	-	132.2[1]	-	-

1. Value considered representative of weld No. 9-203.

RAI 4.2.2-4 (Units 2 & 3)

The applicant's FSAR Supplement summary description does not specify how the RV beltline materials at Millstone, Units 2 and 3 will be in compliance with the applicable requirements in 10 CFR Part 50, Appendix G, as projected through the expiration of the extended periods of operation. Specifically, the applicant has not stated which materials are limiting, and their corresponding USE values, to demonstrate that the applicable requirements were met. Therefore, the staff requests the applicant to include this information in the FSAR Supplement, so that an adequate description of this TLAA is provided, as required by 10 CFR 54.21(d).

Dominion Response:

Unit 2

Upper shelf energy values for the limiting Millstone Unit 2 reactor pressure vessel beltline materials have been calculated in accordance with 10 CFR 50.61 using the most recent material property information through the period of extended operation. These results, discussed in Millstone Unit 2 LRA Section 4.2.2 (presented in LRA Table 4.2-1), demonstrate acceptable USE values through the period of extended operation. The Millstone Unit 2 limiting beltline materials and their associated USE values are identified in Table 1a.

Unit 3

Upper shelf energy values for the limiting Millstone Unit 3 reactor pressure vessel beltline materials have been calculated in accordance with 10 CFR 50.61 using the most recent material property information through the period of extended operation. These results, discussed in Millstone Unit 3 LRA Section 4.2.2 (presented in LRA Table 4.2-1), demonstrate acceptable USE values through the period of extended operation. The Millstone Unit 3 limiting beltline materials and their associated USE values are identified in Table 1b.

Table 1a
Millstone Unit 2
Calculated USE Values at 54 EFPY

Material Description				Initial USE Ft-lbs	Fluence 1/4t E19 n/cm^2	USE[1] Ft-lbs	% Drop USE
Reactor Pressure Vessel Beltline Region Location	Material Identification	Heat Number	Type				
Intermediate Shell	C-505-1	C5843-1	SA-533B Cl.1	88.1	2.30	64.8	26.5
Intermediate Shell	C-505-2	C5843-2	SA-533B Cl.1	89.3	2.30	65.6	26.5
Intermediate Shell	C-505-3	C5843-3	SA-533B Cl.1	94.6	2.53	68.8	27.3
Lower Shell	C-506-1	C5667-1	SA-533B Cl.1	108.0	2.41	76.1	29.5
Lower Shell	C-506-2	C5667-2	SA-533B Cl.1	86.1	2.41	60.7	29.5
Lower Shell	C-506-3	C5518-1	SA-533B Cl.1	88.1	2.41	63.0	28.5
Mid. Circumferential Weld	9-203	90136	Linde 0091	132.2	2.41	68.7	48.0
Mid. Circumferential Weld	9-203	10137	Linde 0091	132.2	2.41	74.0	44.0
Int. Longitudinal Welds	2-203A, B, C	A8746	Linde 124	83.5	1.96	54.3	35.0
Lower Longitudinal Weld	3-203A, B, C	A8746	Linde 124	83.5	1.96	54.3	35.0

1. Regulatory Guide 1.99, Revision 2, Position 1

Table 1b
Millstone Unit 3
Calculated USE Values at 54 EFPY

Material Description				Initial USE Ft-lbs	Fluence 1/4t E19 n/cm^2	USE[1] Ft-lbs	% Drop USE
Reactor Pressure Vessel Beltline Region Location	Material Identification	Heat Number	Type				
Intermediate Shell	B9805-1	C4039-2	SA-533B Cl.1	113.3	1.97	88.0	22.3
Intermediate Shell	B9805-2	C4068-1	SA-533B Cl.1	90.0	1.97	69.9	22.3
Intermediate Shell	B9805-3	C4028-1	SA-533B Cl.1	106.3	1.97	82.6	22.3
Lower Shell	B9820-1	B8961-1	SA-533B Cl.1	76.7	1.97	59.6	22.3
Lower Shell	B9820-2	D1242-2	SA-533B Cl.1	75.7	1.97	58.8	22.3
Lower Shell	B9820-3	D1242-1	SA-533B Cl.1	79.3	1.97	61.6	22.3
All Welds	-	4P6052	Linde 0091	144.0	1.97	111.9	22.3

1. Regulatory Guide 1.99, Revision 2, Position 1

RAI 4.2.3-1 (Units 2 & 3)

The applicant's FSAR Supplement summary description for Millstone, Units 2 and 3, does not specify how the RV beltline materials at Millstone, Units 2 and 3 will be in compliance with the applicable requirements in 10 CFR Part 50, Appendix G, as projected through the expiration of the extended periods of operation. Specifically, the applicant has not stated which materials are limiting, and their corresponding RT_{PTS} values, to demonstrate that the applicable requirements were met. Therefore, the staff requests the applicant to include this information in the FSAR Supplement, so that an adequate description of this TLAA is provided, as required by 10 CFR 54.21(d).

Dominion Response:

Unit 2

The RT_{PTS} values for the limiting Millstone Unit 2 reactor pressure vessel beltline materials have been calculated consistent with Regulatory Guide 1.99, Revision 2 requirements through the period of extended operation. These results, discussed in Millstone Unit 2 LRA Section 4.2.3 (presented in LRA Table 4.2-2), demonstrate that the RT_{PTS} screening criteria have been met in all cases through the period of extended operation. The Millstone Unit 2 limiting beltline materials and their associated RT_{PTS} values are identified in Table 1a.

Unit 3

The RT_{PTS} values for the limiting Millstone Unit 3 reactor pressure vessel beltline materials have been calculated consistent with Regulatory Guide 1.99, Revision 2 requirements through the period of extended operation. These results, discussed in Millstone Unit 3 LRA Section 4.2.3 (presented in LRA Table 4.2-2), demonstrate that the RT_{PTS} screening criteria have been met in all cases through the period of extended operation. The Millstone Unit 3 limiting beltline materials and their associated RT_{PTS} values are identified in Table 1b.

Table 1a
Millstone Unit 2
Calculated RT_{PTS} Values at 54 EFPY

Material Description				Initial RT_{NDT} °F	Chemistry Factor °F	Inner Surface Fluence E19 n/cm^2	Margin °F	ΔRT_{PTS} °F	RT_{PTS} °F
Reactor Vessel Beltline Region Location	Material Identification	Heat Number	Type						
Intermediate Shell	C-505-1	C5843-1	SA-533B Cl.1	8.1[1]	91.3[2]	3.86	34.0	123.1	165.2
Intermediate Shell	C-505-2	C5843-2	SA-533B Cl.1	17.5[1]	91.5[2]	3.86	34.0	123.4	174.9
Intermediate Shell	C-505-3	C5843-3	SA-533B Cl.1	5.0[1]	91.5[2]	4.25	34.0	125.3	164.3
Lower Shell	C-506-1	C5667-1	SA-533B Cl.1	7.0[1]	110.0[2]	4.05	34.0	149.5	190.5
Lower Shell	C-506-2	C5667-2	SA-533B Cl.1	-33.7[3]	110.0[2]	4.05	34.0	149.5	149.8
Lower Shell	C-506-3	C5518-1	SA-533B Cl.1	-19.2[3]	101.5[2]	4.05	34.0	137.9	152.7
Mid. Circ. Weld	9-203	90136	Linde 0091	-56.3[1]	124.3[2]	4.05	56.0	168.9	168.6
Mid. Circ. Weld	9-203	10137	Linde 0091	-56.3[4]	100.0[2]	4.05	56.0	135.9	135.6
Int. Long. Welds	2-203A, B, C	A8746	Linde 0091	-56.0[4]	77.7[2]	3.29	66.0	102.0	112.0
Lower Long. Weld	3-203A, B, C	A8746	Linde 0091	-56.0[4]	77.7[2]	3.29	66.0	102.0	112.0

1. Measured Value
2. Regulatory Guide 1.99, Revision 2, Position 1
3. MTEB 5-2 Positions 1.1(3)(b) and 1.2
4. Generic

Table 1b
Millstone Unit 3
Calculated RT_{PTS} Values at 54 EFPY

Material Description				Initial RT_{NDT} °F	Chemistry Factor °F	Inner Surface Fluence E19 n/cm^2	Margin °F	ΔRT_{PTS} °F	RT_{PTS} °F
Reactor Vessel Beltline Region Location	Material Identification	Heat Number	Type						
Intermediate Shell	B9805-1	C4039-2	SA-533B Cl.1	60.0[1]	31.0[2]	3.31	34.0	40.7	134.7
Intermediate Shell	B9805-2	C4068-1	SA-533B Cl.1	6.2[1]	31.0[2]	3.31	34.0	40.7	80.9
Intermediate Shell	B9805-3	C4028-1	SA-533B Cl.1	-3.3[1]	31.0[2]	3.31	34.0	40.7	71.4
Lower Shell	B9820-1	B8961-1	SA-533B Cl.1	7.0[1]	51.0[2]	3.31	34.0	67.0	108.0
Lower Shell	B9820-2	D1242-2	SA-533B Cl.1	38.8	44.0[2]	3.31	34.0	57.8	130.6
Lower Shell	B9820-3	D1242-1	SA-533B Cl.1	18.6	37.0[2]	3.31	34.0	48.6	101.2
All Welds	-	4P6052	Linde 0091	-50.0[1]	31.7[2]	3.31	56.0	47.7	47.7

1. Measured Value
2. Regulatory Guide 1.99, Revision 2, Position 1

RAI 4.2.4-1

Section 4.2.4 of the Millstone, Units 2 and 3, LRA states that in accordance with 10 CFR 50, Appendix G, updated pressure-temperature limits for the period of extended operation will be developed and implemented prior to the period of extended operation. However, there is no mention of what fluence methodology will be used in developing the P-T limits and how these P-T limits will be implemented. Therefore, the staff requests whether the applicant will use a fluence methodology in accordance with RG 1.190 when developing the P-T limits for the extended period of operation and implemented by the license amendment process (i.e., modification of technical specifications)? This information should also be included in Section A3.1.3 of the LRA (FSAR Supplement) to provide a summary description of the programs and activities for managing the TLAA for the period of extend operation as required by 10 CFR 54.21.

Dominion Response:

The following information will be added to the Millstone Unit 2 and Millstone Unit 3 LRA Appendix A "FSAR Supplement", Section A3.1.3, Pressure-Temperature Limits:

> "Millstone Unit [2] [3] will continue to calculate P-T limits based on fluence values developed in accordance with Regulatory Guide-1.190 requirements, as amended or superseded by future regulatory guidance changes, through the period of extended operation."

RAI 4.3.1-1 (Unit 2)

Section 4.3.1 of the LRA describes the monitoring of design transients at Millstone Unit 2. The LRA indicates that FatiguePro software is used to monitor the number of significant transient cycles and that stress-based fatigue monitoring is used at locations of high fatigue usage. List the locations where stress-based fatigue monitoring is used. Indicate the length of time the FatiguePro software has been used at Millstone Unit 2. Describe how the number of transient cycles and fatigue usage was determined prior to installation of the FatiguePro software.

Dominion Response:

Stress-based fatigue monitoring is used at the pressurizer surge nozzle and the RCS hot leg surge nozzle. FatiguePro software, installed in November 2003, has been used to analyze Millstone Unit 2 process computer data from 1996 to the present. Prior to 1996, transient cycles and associated fatigue usage factors were determined through evaluation of operator log data.

Plant process computer data from 1996 through 2003 was analyzed using FatiguePro to identify transient cycles and associated usage factors. Operator logs were used to identify transient occurrences prior to 1996. Cumulative usage associated with transients prior to 1996 was estimated by applying the per-transient usage calculated with the 1996 through 2003 plant process computer data. The historical transient cycle count and per-transient usage was then used to project 60-year cycle counts and associated usage.

RAI 4.3.1-1 (Unit 3)

Section 4.3.1 of the LRA describes the monitoring of design transients at Millstone Unit 3. The LRA indicates that FatiguePro software is used to monitor the number of significant transient cycles and that stress-based fatigue monitoring is used at locations of high fatigue usage. List the locations where stress-based fatigue monitoring is used. Indicate the length of time the FatiguePro software has been used at Millstone Unit 3. Describe how the number of transient cycles and fatigue usage was determined prior to installation of the FatiguePro software.

Dominion Response:

Stress-based fatigue monitoring is used at the pressurizer surge nozzle, pressurizer heater penetration, the RCS hot leg surge nozzle, the charging nozzle, safety injection nozzle and RHR tee. FatiguePro software, installed in November 2003, has been used to analyze Millstone Unit 3 process computer data from 1996 to the present. Prior to 1996, transient cycles and associated fatigue usage factors were determined through evaluation of operator log data.

Plant process computer data from 1996 through 2003 was analyzed using FatiguePro to identify transient cycles and associated usage factors. Operator logs were used to identify transient occurrences prior to 1996. Cumulative usage associated with transients prior to 1996 was estimated by applying the per-transient usage calculated with the 1996 through 2003 plant process computer data. The historical transient cycle count and per-transient usage was then used to project 60-year cycle counts and associated usage.

RAI 4.3.1-2 (Unit 2)

Note 4 to Table 4.3-2 of the LRA indicates that loading and unloading and step load change cycles are not counted because the transients produce insignificant fatigue usage contributions to any Class 1 component. Indicate whether these transients had any contribution to the cumulative usage factors for the vessel inlet/outlet nozzles reported in Table 4.3-3 of the LRA. Provide a summary of the load pairs that contribute to the fatigue usage of the vessel inlet/outlet nozzles and the corresponding fatigue usage for each load pair.

Dominion Response:

A clarification of Note 4 of Millstone Unit 2 LRA Table 4.3-2 is that the loading and unloading and step load change cycles are not specifically counted (i.e., tracked) because the transients produce either insignificant fatigue usage contributions to any Class 1 component, or the fatigue usage contribution is accounted for in the ongoing fatigue usage tracking of the component by assuming the full design number of loading and unloading and step change events in the cumulative usage factor (CUF). Using the number of design cycles is considered conservative based on plant operation.

The CUF values contained in Millstone Unit 2 LRA Table 4.3-3 are from the RPV stress report. The loading and unloading cycles and step load changes contributed a significant portion of the design fatigue usage of the RPV inlet and outlet nozzles (0.0333 of 0.0496 for the inlet nozzle, and 0.05697 of 0.07878 for the outlet nozzle). It should be noted that the RPV inlet and outlet nozzle CUF values in LRA Table 4.3-3 are reversed. The following Tables 1 and 2 provide the requested load pairs and associated fatigue usage contributions for the RPV inlet and outlet nozzles.

For the inlet nozzles, the RPV stress report identifies that the plant loading/unloading transient contributed 0.0333 usage (total inlet nozzle usage is 0.0496). Applying the worst case F_{en} of 2.53 to the total inlet nozzle usage results in a 60-year usage, including environmental effects, of 0.1255. Although the loading/unloading transient is the major contributor to total fatigue usage, the CUF remains well below 1.0.

For the outlet nozzles, the RPV stress report identifies that the plant loading/unloading transient contributed 0.05697 usage (total outlet nozzle usage is 0.07878). Applying the worst case F_{en} of 2.53 to the total inlet nozzle usage results in a 60-year usage, including environmental effects, of 0.1993. Although the loading/unloading transient is the major contributor to total fatigue usage, the CUF remains well below 1.0.

Table 1
Load Pairs - Inlet Nozzle

Transient 1	Transient 2	SI(1) (max)	SI(1) (min)	SI(1) (alt)	n(2)	N(3)	U(4)
Initial Hydro.	Loss of Secondary Pressure	86.95	-8.67	47.81	5	4,900	0.0010
Initial Hydro.	Initial Hydro.	86.95	0.68	43.135	5	6,700	0.0007
Leak Test	Leak Test	70.15	0.38	34.885	200	13,800	0.0145
Plant Unloading	Plant Heatup	68.59	0.68	33.955	500	15,000	0.0333
Plant Unloading	Loss of Flow	68.59	56.58	6.005	40	$1x10^{10}$	0.0000
Total CUF	-	-	-	-	-	-	0.0496

1. Stress Intensity (ksi).
2. Number of cycles analyzed for load pair Transient 1 and Transient 2.
3. Allowable cycles for alternating stress range, SI (alt).
4. Incremental usage factor.

Table 2
Load Pairs - Outlet Nozzle

Transient 1	Transient 2	SI[1] (max)	SI[1] (min)	SI[1] (alt)	n[2]	N[3]	U[4]
Loss of Secondary Pressure	Plant Heatup	27.07	-38.82	32.96	5	17,000	0.00029
Plant Cooldown	Plant Heatup	20.82	-38.82	29.82	495	23,000	0.02152
Leak Test	Plant Loading	19.12	-36.69	27.91	200	28,000	0.00714
Initial Hydro	Plant Loading	17.6	-36.69	27.1	10	32,000	0.00031
Loss of Flow	Plant Loading	-2.71	-36.69	16.99	40	200,000	0.00020
Reactor Trip	Plant Loading	-4.98	-36.69	15.86	400	270,000	0.00148
Abnormal Loss of Load	Plant Loading	-5.21	-36.69	15.74	40	280,000	0.00014
Plant Unloading	Plant Loading	-5.43	-36.69	15.61	14310	300,000	0.04770
Step Decrease	Step Increase	-21.63	-25.89	2.13	2000	∞	0.00000
Total CUF	-	-	-	-	-	-	0.07878

1. Stress Intensity (ksi).
2. Number of cycles analyzed for load pair Transient 1 and Transient 2.
3. Allowable cycles for alternating stress range, SI (alt).
4. Incremental usage factor.

RAI 4.3.1-2 (Unit 3)

Northeast Utilities submitted the results of an evaluation of the Millstone Unit 3 surge line to the NRC in response to NRC Bulletin 88-11 (reference 4.8-36 of the LRA). The submittal indicated that the maximum calculated fatigue usage for the surge line at the RCL hot leg nozzle was 0.434. Table 4.3-3 of the LRA indicates that the maximum fatigue usage for the surge line is 0.0796. Provide the basis for the usage factor report in Table 4.3-3 of the LRA.

Dominion Response:

The original cumulative usage factor for the surge line at the RCS hot leg nozzle employing the design number of cycles is 0.434. The recalculated cumulative usage factor employing the projected number of cycles (Millstone Unit 3 LRA, Table 4.3-2) for the period of extended operation is 0.0796.

The 60-year cumulative usage factor for the RCS hot leg nozzle was recalculated using the Millstone Unit 3 FatiguePro software to evaluate actual operating data obtained from the plant process computer. Evaluation of plant process computer data resulted in the development of a per cycle fatigue usage factor. This factor was then applied to the projected number of 60-year cycles to determine the 60-year cumulative fatigue usage factor. Use of actual operating experience (reflecting MOP use from initial unit startup) results in the development of a more accurate Millstone Unit 3 RCS hot leg nozzle cumulative usage factor of 0.0796.

RAI 4.3.1-4

The Westinghouse Owners Group has issued the generic Topical Report WCAP-14574-A to address aging management of pressurizers. The staff's review of WCAP-14574-A identified a number of issues that should be addressed on a plant specific basis. Renewal Applicant Action Item 1 requests the applicant to demonstrate that the pressurizer sub-component CUFs remain below 1.0 for the period of extended operation. Table 2-10 of WCAP-14574-A indicates that the ASME Section III Class 1 fatigue CUF criterion could be exceed at several pressurizer sub- component locations during the period of extended operation. WCAP-14574-A also identified recent unanticipated transients that were not considered in the original ASME Section III Class 1 fatigue analyses, including inflow/outflow thermal transients. Provide the following information:

a. Confirm that the additional transients discussed in WCAP-14574-A, not considered in the original design, have been addressed at Millstone Unit 3.

b. Show the ASME Section III Class 1 CLB CUFs for the applicable sub-components of the FNP pressurizers specified in Table 2-10 of WCAP-14574-A and the corresponding CUFs for the extended period of operation.

c. Discuss the impact of the environmental fatigue correlations provided in NUREG/CR- 6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," on the above results.

Dominion Response:

a. The pressurizer lower head and pressurizer surge nozzle were evaluated for fatigue considering the effects of all loadings, including thermal stratification in the surge line and pressurizer lower head (insurge/outsurge). These loadings include the additional transients discussed in WCAP-14574-A (insurge/outsurge transient). This evaluation was performed using the FatiguePro software. This software is configured to compute transient stress and fatigue usage for components in the pressurizer lower head and surge line, accounting for all applicable thermal and pressure effects (including thermal stratification) in the pressurizer lower head and surge line.

b. Table 1 provides the ASME Section III CLB cumulative fatigue usage values for the applicable subcomponents of the Millstone Unit 3 pressurizer. The values shown are the corresponding CUF values for the period of extended operation.

c. An environmentally assisted fatigue evaluation was performed for the Millstone Unit 3 pressurizer surge line (Millstone Unit 3 LRA Section 4 - Table 4.3-3). Millstone Unit 3 has committed (E. S. Grecheck to NRC, *Millstone Power Station Units 2 and 3 – Additional Information in Support of Applications for Renewed Operating Licenses*, Serial No. 04-320 dated July 7, 2004, Audit Item 20) to follow industry efforts that will provide specific guidance to license renewal applicants for evaluating the environmental effects of fatigue on applicable locations, other than those identified in NUREG/CR-6260. Millstone Unit 3 will implement the appropriate recommendations resulting from this guidance.

   For the commitment regarding environmentally assisted fatigue, the wording "Until these recommendations are available, Millstone 3 commits to using the pressurizer surge line nozzle as a leading indicator to address environmental effects on fatigue of pressurizer sub-components during the period of extended operation." will be added to Item 29 for Unit 3 in Appendix A, "FSAR Supplement", Table A6.0-1 License Renewal Commitments and Section A3.2.3 (page A-27).

Table 1
Cumulative Usage Factor (CUF)
Pressurizer Components

Component	CUF
Upper Head	0.90
Shell	0.97
Spray Nozzle	0.058
Safety and Relief	0.005895
Manway Bolt	Satisfied[1]
Manway Cover	Satisfied[1]
Manway Pad	Satisfied[1]
Valve Support Bracket	0.618
Seismic Support Lugs	0.3704
Lower Head	0.857
Heater Well	0.13
Immersion Heater	<0.12
Surge Nozzle	0.599
Instrument Nozzle	≤ 0.16
Support Skirt and Flange	<0.73

1. Exempted from fatigue evaluation per ASME Section III, NB-3222.4(d).

RAI 4.5-2 (Unit 2)

The lowest required prestressing force for each group of tendons is established based on the computations of minimum requirement to counteract the tension produced due to specified internal pressure. The tendon spacing would be based on the tendon lock-off forces minus the estimates of losses due anchorage take-up, elastic shortening, time-dependent losses, and losses due to friction. It is not feasible to count for all these factors and end up with the same minimum required tendon force (1308 kips) at tendon anchorages for hoop, vertical, and dome tendons. The applicant is requested to provide the basis for establishing the minimum required forces to compare against the measured prestressing forces.

Dominion Response:

The Millstone Unit 2 containment is pre-stressed by a post-tensioning system composed of dome, vertical and horizontal (hoop) tendon groups.

Each tendon consists of approximately 186 stabilized, low relaxation 0.250-inch diameter wires, each having a tensile strength of 240,000 psi. The design of the post tensioning system takes into consideration a number of factors including tendon spacing, steel relaxation, stress losses due to concrete creep, steel elasticity, number of tendon wires and variability in same tendon load readings. Taking these variables into consideration, Dominion originally used a value of 1308 kips for the minimum pre-stress forces (Millstone Unit 2 LRA, Section 4 – Tables 4.5-1, -2 and -3, and Figure 4.5-1) as a nominal value considered to represent a bounding pre-stress force for all three tendon groups. However, based on a conversation with the reviewer, Dominion decided to determine the actual values for the Millstone Unit 2 containment dome, vertical and horizontal (hoop) tendon groups, which are 1343 kips, 1339 kips and 1325 kips respectively.

As presented in the responses to RAI 4.5-4 (Figures 1, 2 and 3) and RAI 4.5-5 (Figures 1, 2 and 3), projected lockoff forces (Millstone Unit 2 LRA, Section 4 – Figure 4.5-1) remain above minimum requirements over the period of extended operation.

RAI 4.5-3 (Unit 2)

Normal tendon inspection results consist of the estimated tendon forces (based on the factors cited in RAI 4.5-1) and the measured lift-off forces of the sampled tendons to satisfy the requirements of IWL-3221.1(a) and (b), and 10 CFR 50.55a(b)(2)(viii)(B). The applicant is requested to explain the "values" entered in the second column of Tables 4.5-1, 4.5-2, and 4.5-3, and how these values are related to the estimated and measured prestressing forces at various times.

Dominion Response:

The second column of Millstone Unit 2 LRA Section 4 - Tables 4.5-1, 4.5-2 and 4.5-3 represents the as found (actual values) developed using the most recent containment tendon inspection data. The as found values are projected, through the use of regression analysis, through the period of extended operation.

Tendon force data developed in accordance with Regulatory Guide 1.35, Revision 1 requirements (3, 5 and 10-year inspections) was not used for trending purposes since this revision required repetitive detensioning and retensioning of the same tendon groups. Prestressing forces for the 15, 20 and 25-year containment tendon inspections were developed using the requirements of Regulatory Guide 1.35, Revision 3. Only prestressing forces from previously untested tendons are used for projection purposes. Since containment tendon examinations are performed on 5-year intervals, per Regulatory Guide 1.35 Revision 1, tendon force projections will be refined and updated following each inspection.

RAI 4.5-4

The number of tendons sampled (i.e.: 4% and 2% of the population of the group of tendons) during each tendon inspection is small, and it would require the t- distribution for establishing confidence levels (Column 3 of Tables 4.5-1, 4.5-2, and 4.5-3) during each inspection based on the measured results. Recognizing the fact that the sample size during each tendon inspection is small, and the pattern of measured tendon forces around the expected value is quite irregular, Attachment 3 of NRC Information Notice 99-10, Revision 1, recommends regression analysis of the measured tendon forces without averaging or any statistical calculation. Based on the above discussion, the applicant is requested to provide more information about the values in column 3 of the Tables and a tabulation of measured tendon force values (raw) for each group of tendons used in the regression analysis.

Dominion Response:

A regression analysis has been performed for the individual tendon groups based upon the recommendations of NRC Information Notice 99-10. The tabulated as found (raw) tendon force data used in the regression analysis is presented in the following Tables 1, 2 and 3. The 95% confidence values were calculated using a sigma value representing the standard deviation of errors from the individual tendon group (dome, vertical and horizontal) regression analysis equations.

As a supplement to the regression analysis results contained in the response to RAI 4.5-5, the raw dome, vertical and horizontal tendon force data contained in Tables 1, 2 and 3 was used to develop the indicated best-fit trend-lines in Figures 1, 2 and 3. Tendon force data developed in accordance with Regulatory Guide 1.35, Revision 1 requirements (3, 5 and 10-year inspections) was not used for trending purposes since this revision required repetitive detensioning and retensioning of the same tendon groups. Prestressing forces for the 15, 20 and 25-year containment tendon inspections were developed using the requirements of Regulatory Guide 1.35, Revision 3. Only prestressing forces from previously untested tendons are used for projection purposes.

Table 1
Dome Tendon Regression Analysis
(Raw Data)

Tendon Number	Tendon Force (kips)	Test Date	Originally Stressed	Age (Years Stressed)
1D24	1447	06/16/01	03/27/73	28.241
2D10	1514	07/08/01	04/08/73(1)	28.268
3D04	1463.5	08/08/01	04/08/73(1)	28.353
1D24	1437	03/30/96	03/27/73	23.025
2D03	1474	03/17/96	04/08/73(1)	22.956
3D10	1495	02/17/96	04/08/73(1)	22.877
1D24	1512	01/23/92	03/27/73	18.838
2D05	1487	01/31/92	03/12/73	18.901
3D05	1464	01/27/92	03/09/73	18.899
1D21	1548.5	07/06/76	04/13/73	3.233
1D23	1585	07/05/76	04/18/73	3.216
2D04	1563.5	07/04/76	04/18/73	3.214
2D07	1535	07/03/76	03/29/73	3.266
3D06	1550	07/01/76	04/16/73	3.211
3D12	1600	06/02/76	04/30/73	3.093

(1) Average group stressing date; specific date unavailable.

Table 2
Vertical Tendon Regression Analysis
(Raw Data)

Tendon Number	Tendon Force (kips)	Test Date	Originally Stressed	Age (Years Stressed)
12V07	1552	06/01/01	06/16/73[1]	27.978
23V07	1491	06/08/01	06/16/73[1]	27.997
31V24	1489	05/30/01	06/16/73[1]	27.973
12V39	1569	01/17/96	06/16/73[1]	22.603
23V20	1540	02/28/96	06/16/73[1]	22.718
31V24	1486	01/16/96	06/16/73[1]	22.600
12V31	1590	02/04/92	05/10/73	18.751
23V29	1514	01/10/92	07/24/73	18.477
31V22	1582	01/18/92	07/27/73	18.490
31V23	1666	01/14/92	05/16/73	18.677
31V24	1467	01/17/92	03/05/73	18.882
12V27	1610	05/18/76	07/30/73	2.803
23V26[2]	1700	05/29/76	07/24/73	2.849
23V31	1570	05/19/76	05/14/73	3.016
31V15	1540	05/23/76	08/10/73	2.786
31V34	1560	05/21/76	07/25/73	2.825

(1) Average group stressing date; specific date unavailable.
(2) Tendon experienced water intrusion.

Table 3
Horizontal Tendon Regression Analysis
(Raw Data)

Tendon Number	Tendon Force (kips)	Test Date	Originally Stressed	Age (Years Stressed)
12H13	1469	09/11/01	07/30/73[1]	28.137
31H36	1472.7	08/26/01	07/30/73[1]	28.093
32H32	1502.5	08/31/01	07/30/73[1]	28.107
12H05[2]	1520	04/07/96	06/21/73	22.811
31H25	1506	02/14/96	07/30/73[1]	22.559
32H32	1498	04/01/96	07/30/73[1]	22.688
12H01[2]	1467	02/14/92	05/25/73	18.737
12H08[2]	1495	02/11/92	08/08/73	18.523
31H21	1421	02/29/92	07/13/73	18.664
32H37	1559	02/06/92	09/19/73	18.395
32H07	1580	06/10/76	06/08/73	3.008
32H19	1565	06/12/76	07/16/73	2.910
32H33	1630	05/27/76	09/17/73	2.693
12H07	1570	06/19/76	06/21/73	2.997
12H19	1530	06/24/76	07/10/73	2.959
12H33	1550	06/27/76	09/17/73	2.778
31H06	1595	06/09/76	08/10/73	2.833
31H19	1590	06/07/76	07/13/73	2.904
31H32	1590	06/04/76	09/13/73	2.726
31H33	1585	06/06/76	09/13/73	2.732

(1) Average group stressing date; specific date unavailable.
(2) Tendon experienced ground water intrusion.

Figure 1
Millstone Unit 2
Containment Tendon Prestress
Dome Tendons
(Raw Data)

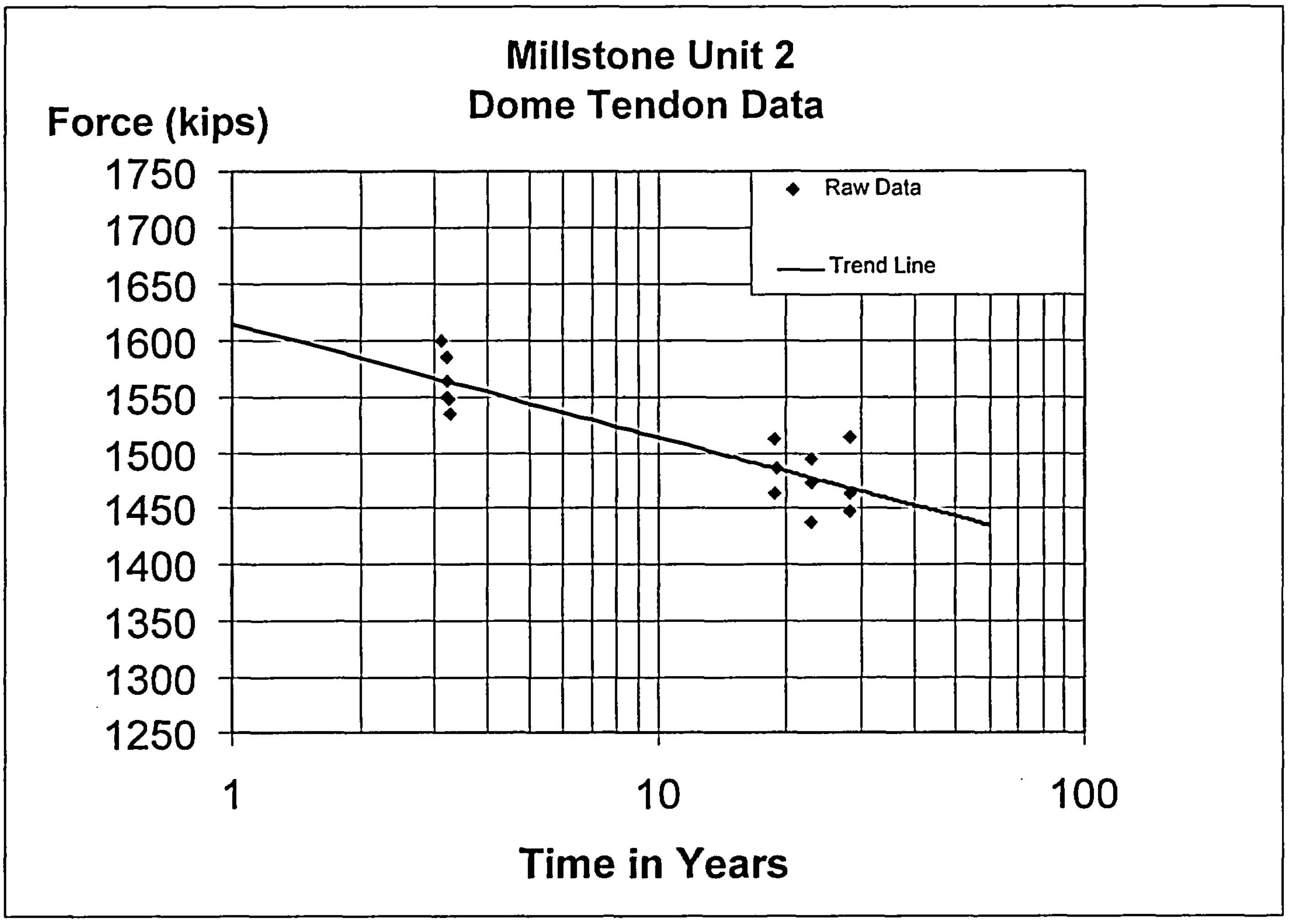


Figure 2
Millstone Unit 2
Containment Tendon Prestress
Vertical Tendons
(Raw Data)

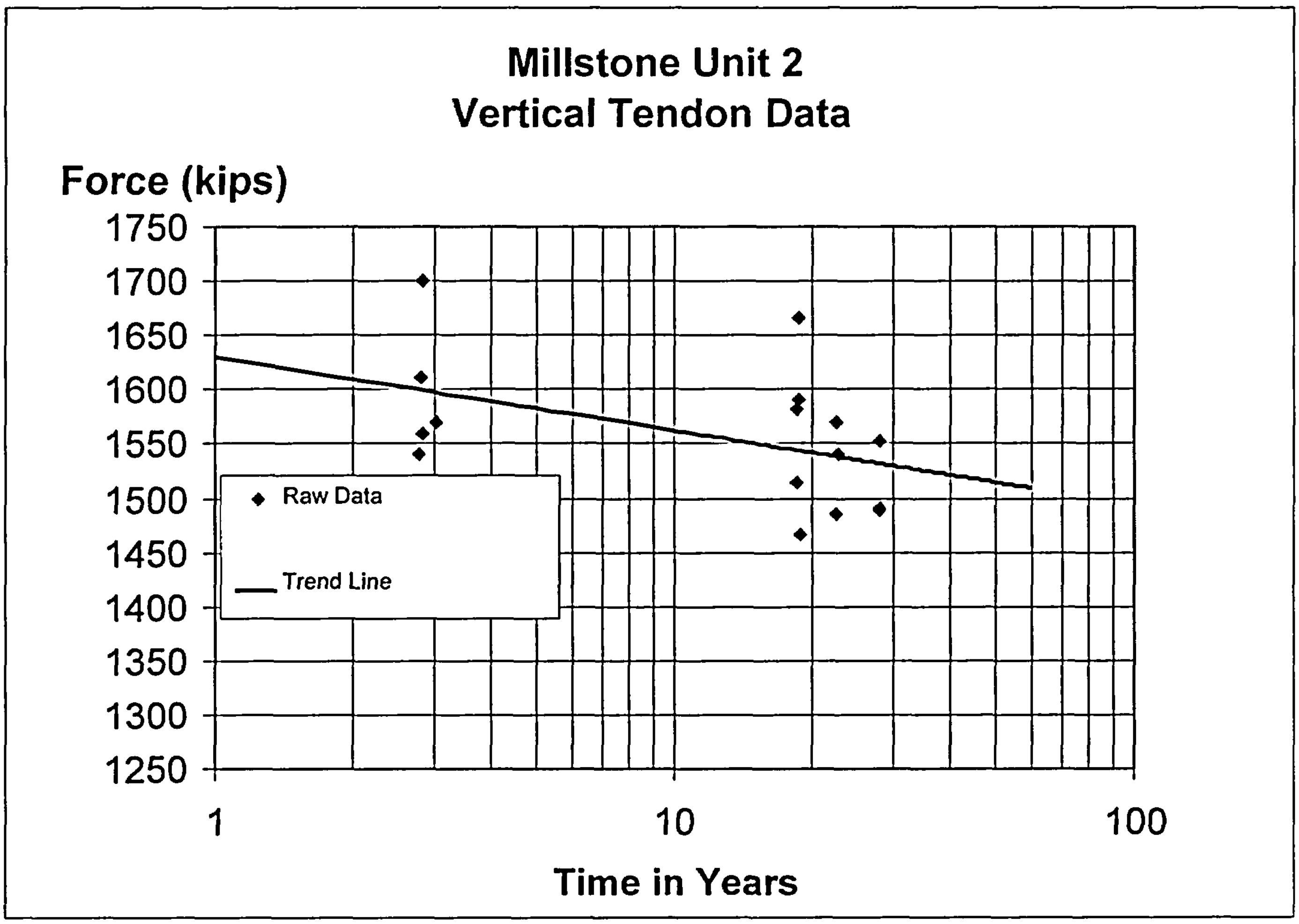
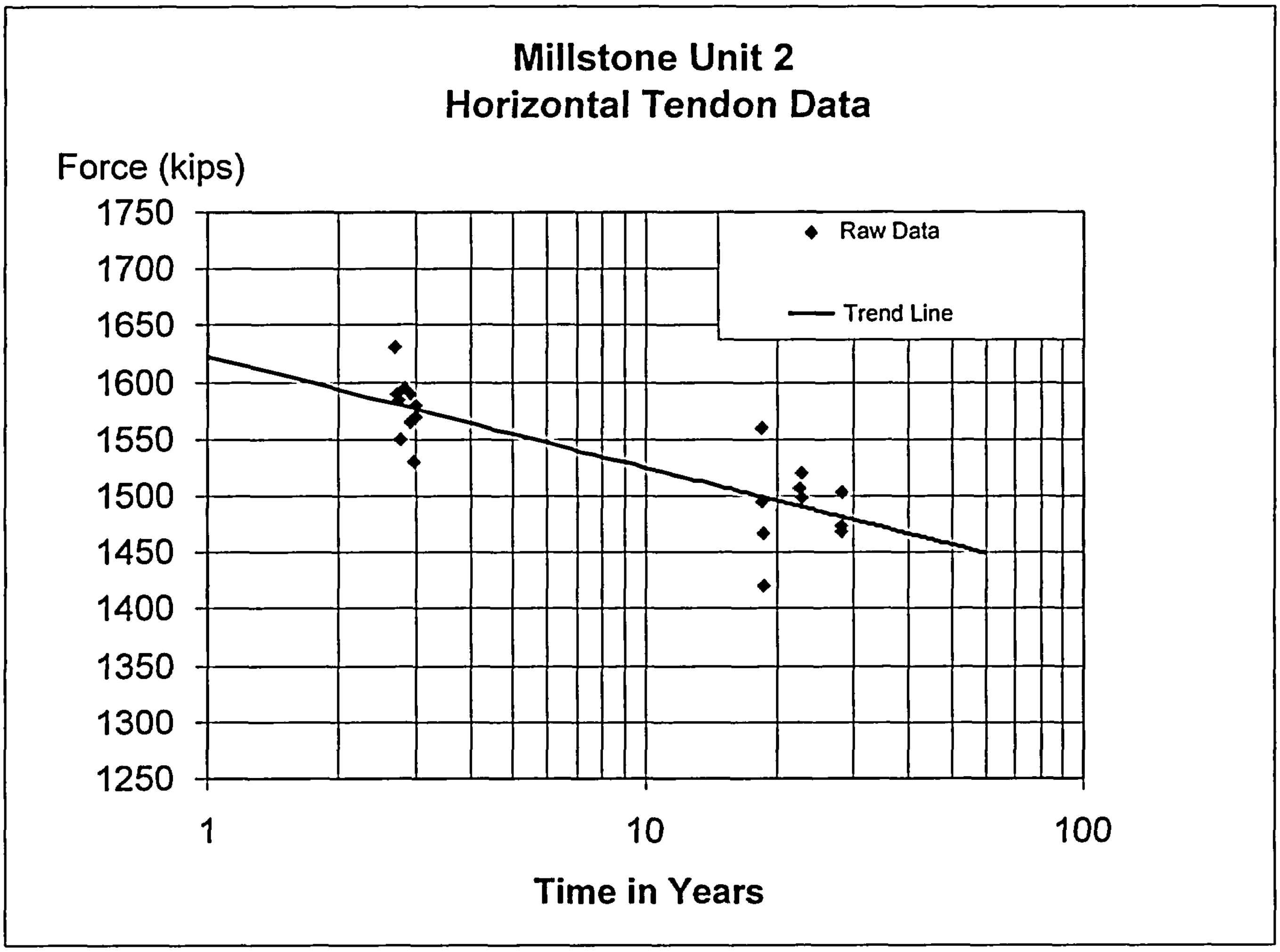


Figure 3
Millstone Unit 2
Containment Tendon Prestress
Horizontal Tendons
(Raw Data)



RAI 4.5-5 (Unit 2)

The process used by the license renewal applicants with prestressed concrete containments, is to assume that the tendon force varies with the logarithm of time (as explained in Regulatory Guide 1.35.1). It is not apparent in figure 4.5-1, what functional relationship has been assumed between the two variables. The applicant is requested to provide additional information regarding the process used in arriving at the trending curves shown in Figure 4.5-1.

Dominion Response:

Consistent with Regulatory Guide 1.35.1, the containment dome, horizontal and vertical tendon surveillance results (Millstone Unit 2 LRA, Section 4, Tables 4.5-1, 4.5-2 and 4.5-3) used in the development of LRA Figure 4.5-1 have been plotted in the following Figures 1, 2 and 3, against the logarithm of time using the methodology identified in Attachment 3 of NRC Information Notice 99-10. Prestressing forces for the Millstone Unit 2 containment dome, horizontal and vertical tendon are shown to vary linearly with time. Further discussion and information on the development of these curves can be found in the responses to RAI 4.5-2, RAI 4.5-4 and RAI 4.5-7.

Figure 1
Millstone Unit 2
Containment Tendon Prestress
Dome Tendons

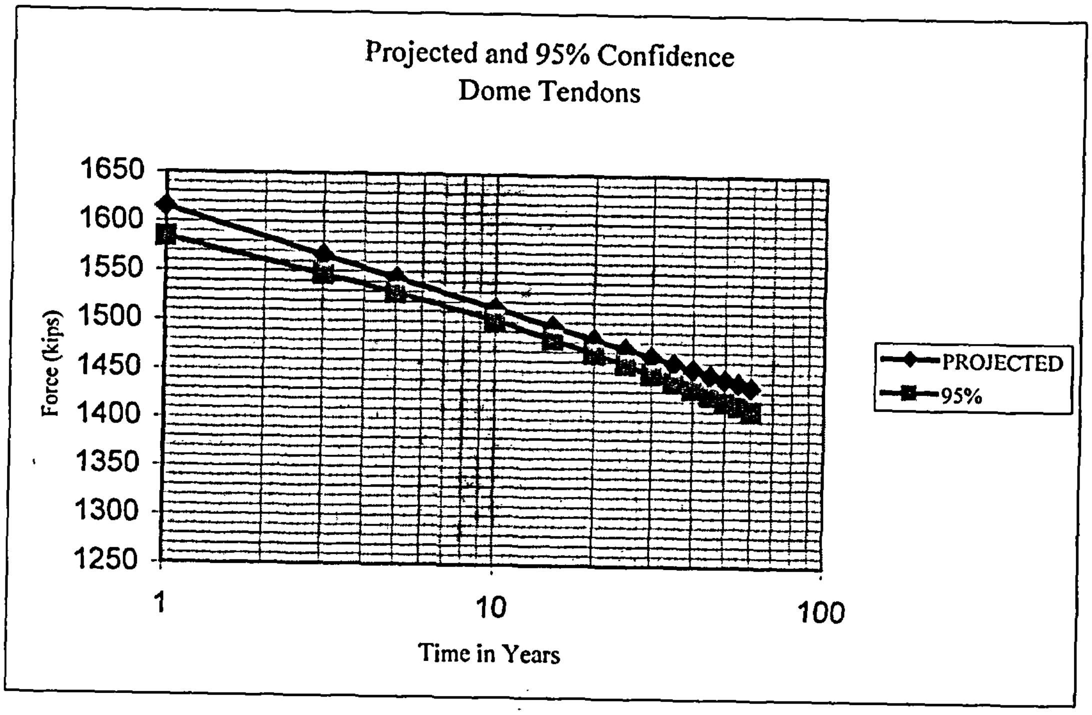


Figure 2
Millstone Unit 2
Containment Tendon Prestress
Vertical Tendons

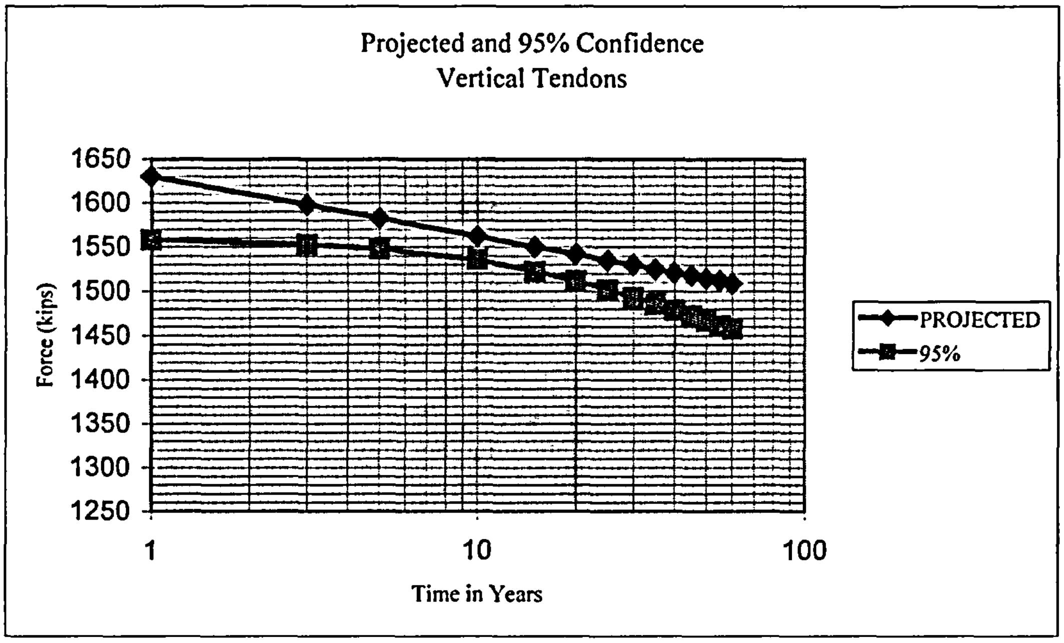
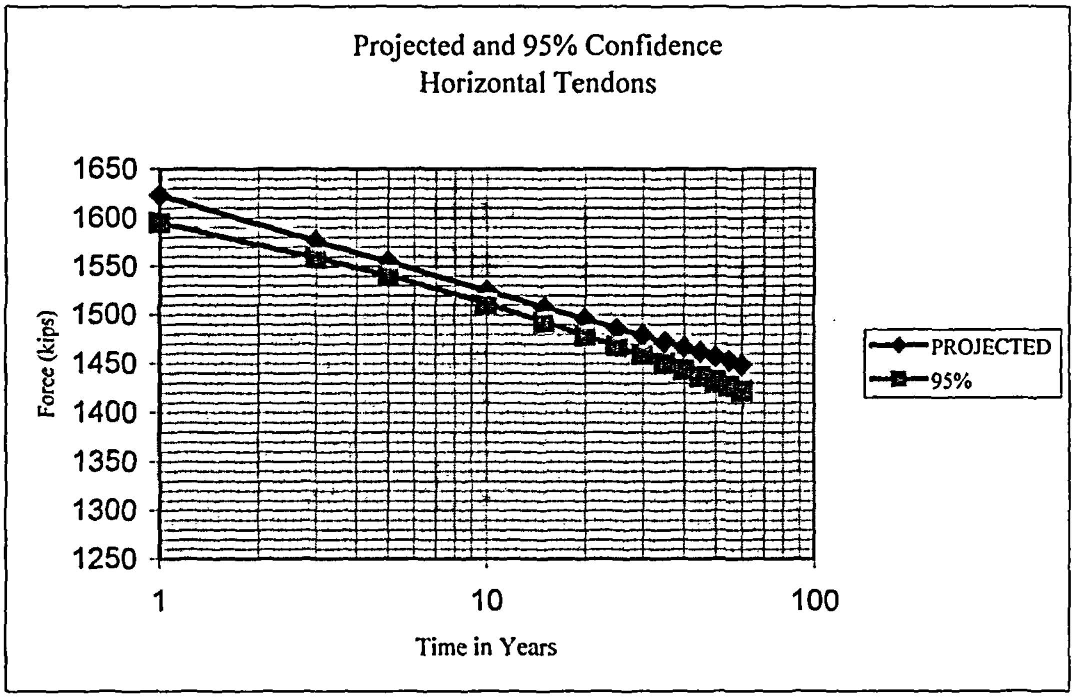


Figure 3
Millstone Unit 2
Containment Tendon Prestress
Horizontal Tendons



RAI 4.7.2-1 (Unit 2)

Discuss how the crack growth rates and the number of start/stop cycles used in the SIR-94-080A are applicable to the period of extended operation for Millstone Unit 2. What is the predicted number of thermal cycles that the reactor coolant pump flywheels are expected to experience in service including the period of extended operation?

Dominion Response:

A flaw tolerance evaluation using linear elastic fracture mechanics principles was performed using lower bound fracture toughness values at the most highly stressed location. A crack growth evaluation was performed using the ASME Section XI crack growth law for ferritic steel in an air environment with an assumed initial flaw size of 0.25 inches (UT detection uncertainty). The crack growth after 4000 startup/shutdown cycles (significantly more than expected for the period of extended operation) was found to be minimal (0.0035 inches) resulting in a final flaw size of 0.2535 inches. This final flaw size is significantly below the calculated ASME Section XI, paragraph IWB-3610 allowable flaw size of 1.64 inches for normal operating speed and greater than 2.0 inches for accident speed conditions. Millstone Unit 2 is expected to experience 300 reactor coolant pump startup/shutdown cycles including the period of extended operation.

RAI 4.7.2

Discuss how the crack growth rates and the number of start/stop cycles used in the WCAP-14535A are applicable to the period of extended operation for Millstone Unit 2. What is the predicted number of cycles that the reactor coolant pump flywheels are expected to experience in service including the period of extended operation?

Dominion Response:

RAI 4.7.2-1 addressed this same issue for Unit 2. It is assumed that Unit 2 was a typo in this RAI and thus, this response was developed for Millstone Unit 3.

Millstone Unit 3 reactor coolant pump flywheel fatigue crack growths have been determined assuming 6,000 reactor coolant pump startup/shutdown cycles in WCAP-14535A. The 6,000 cycles are considered to represent a conservative number of reactor coolant pump startups/shutdowns for a 60-year period of operation. Assuming the presence of a large initial crack, additional crack growth (nominally 0.080 inches) after 6,000 startup/shutdown cycles is considered negligible. As presented in Millstone Unit 3 LRA Section 4 – Table 4.3-2, the bounding reactor coolant pump is expected to experience 272 startup/shutdown cycles including those expected during the period of extended operation.

RAI 4.7.3-1

In Section 4.7.3 of the LRA for Millstone Unit 2, the applicant concludes that the evaluation of the reactor coolant pump casings is a TLAA per 10 CFR 54.3 since it involves the use of time limited assumptions such as thermal cycles, and crack growth rates. Also, Section A3.6.3 of the LRA for Millstone Unit 2 stated that the evaluation of the RCP casings indicates a low likelihood of casing fatigue failure over a 60-year period. In addition, the ASME Code Case N-481 allows a fracture mechanics evaluation to be performed to justify the use of specific visual inspections in lieu of volumetric inspections. The applicant refers to Section B2.1.18 of the LRA for the inspections. However, no fracture mechanics evaluation of the reactor coolant pump casings for the extended period was provided. Provide the following information related to this code case:

a) Provide the fracture mechanics evaluation for the extended period. In addition, compare the crack growth for the extended period to that originally predicted for the current operating period, and provide the basis for concluding that this amount of additional crack growth still allows the continued application of ASME Code Case N-481.

b) ASME Code Case N-481 requires both inspection and a fracture mechanics evaluation. The LRA states that the reactor coolant pump casing will be managed by the Inservice Inspection Program for the extended period of operation consistent with 10 CFR 54.21(c)(1), Option (iii). However, since an evaluation is also required to be performed, the applicant is requested to determine which option of 10 CFR 54.21(c)(1) (Option (i) or Option (ii)) applies for the fracture mechanics evaluation required by the code case, in addition to Option (iii) for the management by inspection.

c) Confirm that the summary description of ASME Code Case N-481 in the FSAR Supplement (Section A3.6.3 of the LRA) and Section 4.7.3 of the LRA applies to the pump casing welds, not the pump casing as a whole, to be consistent with the code case. Also, confirm that the requirements of Table IWB-2500-1, Examination Category B-L-2, Item B12.20 of the ASME Code, Section XI to perform internal visual inspections of the internals of the pump casing still apply.

Dominion Response:

a) The use of Code Case N-481 has been approved for use at Millstone Unit 2 (NRC to J. F. Opeka, *Request for Approval to Implement Provision of ASME Code Case N-481 for Millstone 2 (TAC No. 84246)*, Letter A10811 dated January 11, 1993).

   A fracture mechanics evaluation has been performed for the Millstone Unit 2 reactor coolant pumps. This evaluation, performed as part of a Combustion Engineering

Owners Group CEN-412, Revision 2, Supplement 2 activity included a determination of the time necessary for an assumed 1/4t crack to propagate to an unacceptable size. For Millstone Unit 2, the limiting end-point crack size is 0.39t, significantly greater than the 1/4t flaw postulated in ASME Code Case N-481. The time for the Millstone Unit 2 reactor coolant pump casing to reach the limiting end-point crack size is 103 years.

b) Consistent with 10 CFR 54.21(c)(1), Option (ii), acceptable reactor coolant pump casing flaw sizes have been projected through the period of extended operation.

c) Millstone Unit 2 LRA Section 4.7.3 applies to the reactor coolant pump casing welds. Also, the requirements of Table IWB-2500-1, Examination Category B-L-2, Item B12.20 of the ASME Code, Section XI apply.

RAI 4.7.4-1 (Unit 2)

The applicant states, "The number and characteristics of cycles identified in CEN-367-A have been reviewed and found acceptable for the period of extended operation." Although, the leak-before-break fatigue crack growth analysis reported in CEN-367-A is based on 40-year design limits for RCS fatigue transient design limits. Provide justification for the acceptability of the 40-year analysis for the period of extended operation.

Dominion Response:

The 40-year design transients and associated design cycles are identified in Table 1. These transient and design cycles are compared to the projected number of cycles, Millstone Unit 2 LRA Section 4 – Table 4.3-2, through the period of extended operation. Since the number of design cycles remains bounding, CEN-367-A remains acceptable for the period of extended operation.

RAI B2.1.3-1 (Units 2 & 3)

In the operating experience section of Appendix B, B2.1.3, "Boric Acid Corrosion," of the LRA, the applicant states that operating experience indicates that Millstone has been aggressive in the identification and elimination of borated water leakage. Corrective actions have been effectively implemented to mitigate active leakage prior to experiencing a loss of intended function. Discuss how program revisions have incorporated lessons learned from the Davis-Besse vessel head degradation, the control rod drive mechanism penetration cracking and the bottom mounted instrumentation (BMI) nozzles to the lower RV heads discussed in NRC Bulletins 2002-01, 2002-02, 2003-02, and NRC Order EA-03-009 to prevent reoccurrence of degradation caused by boric acid leakage, as required by Generic Letter 88-05. This discussion should include the identification of component locations that have been added to the scope of the program and clarify what type of visual examinations (i.e., specify whether VT-1, VT-2 or VT-3, and whether the visual examinations are enhanced, bare-surface, qualified, etc.) will be performed on the components.

Dominion Response:

The following is a representative list of applicable component locations and corresponding examination methods, which have been incorporated into the Boric Acid Corrosion Control (BACC) Program to address operating experience, lessons learned from Davis-Besse, the identified NRC bulletins, and the NRC order.

- After Fort Calhoun reported leakage from a pressurizer heater or instrument penetration in December of 2001, Millstone added the bare metal visual examination of heater sleeves and instrument nozzles on the pressurizer to the GL 88-05 inspection procedure starting with the April 2002 refueling outage (2R14) for Millstone Unit 2. These examinations found two leaking heater sleeves. Both were repaired with Mechanical Nozzle Seal Assembly (MNSA) clamps.

- In the fall outage of 2002 (3RO8), Millstone Unit 3 performed bare metal visual examinations of the reactor vessel head penetrations under the insulation of the reactor vessel head even though it was in the low susceptibility category according to NRC Bulletin 2002-02. 3R08 was the first outage after NRC Bulletin 2002-02 was issued. The results of this examination concluded that there was no evidence of material degradation or RCS leakage.

- In the fall of 2002, bare metal examinations of the instrumentation nozzles on the reactor coolant piping and steam generators for Millstone Unit 2 were added to the inspection procedure.

- In February 2003, Dominion instituted a corporate level program to manage borated water leakage for Millstone, North Anna, and Surry.

- In the fall outage of 2003 (2R15), Millstone Unit 2 performed bare metal visual examinations of the pressurizer heater sleeves and all of the instrument nozzles and repeated 100% ultrasonic testing (UT) of the reactor pressure vessel penetrations in accordance with NRC Order EA-03-009. Two leaking heater sleeves and 11 cracked reactor pressure vessel penetrations were identified. All of the heater sleeves and reactor vessel head penetrations were repaired. No leakage was found on any of the instrumentation nozzles.

- After the Unit 2 fall outage of 2003 (2R15), bare metal visual examinations of Alloy 82/182 butt welds in the Millstone Unit 3 reactor coolant system (RCS) were added to the inspection procedure. Bare metal visual examinations of Alloy 600 RTDs on Millstone Unit 3 were added to the program as a result of operating experience from North Anna and Surry. Bare metal visual examination of the bottom mounted instrumentation (BMI) nozzles on Millstone Unit 3 was added in accordance with NRC Bulletin 2003-02.

- Prior to outage 3R09, the Boric Acid Corrosion Control (BACC) Program procedure was revised into four separate implementing procedures to address the overall program requirements, on-line walkdowns, refueling outage walkdowns, and boric acid corrosion evaluations.

- During outage 3R09, Millstone Unit 3 performed bare metal visual examinations for Alloy 82/182 butt welds (except for RPV nozzles). This included the pressurizer and steam generator pipe connections. Bare metal visual examinations were performed for the BMI nozzles in accordance with NRC Bulletin 2003-02.

- Prior to outage 2R16, Millstone Unit 2 will add bare metal visual examinations of Alloy 82/182 butt welds in the reactor coolant system to the BACC Program.

- As identified in letter S/N 04-140 from Ms. Leslie N. Hartz, Dominion Nuclear Connecticut, to U. S. Nuclear Regulatory Commission, dated June 3, 2004; Dominion announced its intention to replace the pressurizer for Millstone Unit 2 using materials that are resistant to PWSCC. Dominion intends to replace the Unit 2 pressurizer during the Fall 2006 refueling outage.

- In letter B18853 from David A. Christian, "Request for Relaxation from Section IV.C(a)(1) of the Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads", Attachment 1, page 4, Dominion acknowledges its intention to replace the reactor vessel head for Millstone Unit 2. The new vessel head package will use improved materials and the new insulation design will better facilitate future examinations.

RAI B2.1.3-2 (Units 2 & 3)

The applicant's FSAR Supplement summary description for the Boric Acid Corrosion does not provide a reference to commitments made in the applicant's response to Generic Letter (GL) 88-05. Therefore, the staff requests that the applicant amend the FSAR Supplement summary description to provide a more specific reference to the applicant's response (i.e., Dominion's response) to GL 88-05, and to any additional responses to NRC generic communications (i.e., Generic Letters, Bulletins, Orders, or Circular Letters) that are germane to the scope of the AMP, including those responses to NRC Bulletins 2002-01, 2002-02 and 2003-02, and to NRC Order EA-03-009, as appropriate.

Dominion Response:

Dominion's response to Generic Letter 88-05 and subsequent NRC communications on boric acid corrosion and leakage detection, which include NRC Bulletins 2001-01, 2002-01, 2002-02 and 2003-02, and NRC Order EA-03-009 (as revised) are part of the current licensing basis (CLB) for Millstone Units 2 and 3. In accordance with 10CFR54, the CLB will carry forward into the period of extended operation. The specific responses to these NRC generic communications for Millstone Units 2 and 3 are readily retrievable in the NRC Public Document Room. Dominion feels that providing these commitment details in the FSAR Supplement summary would be inconsistent with the level of detail normally presented in the FSAR supplement. Please see the response to RAI B2.1.3-1 for a description of how these NRC generic communications were addressed for Millstone Units 2 and 3.

RAI B2.1.3-3

Section B2.1.3 of the LRA states the following:

"The program addresses the structures and components composed of susceptible materials, which includes carbon and low alloy steels, copper, and cast iron. The program inspects the surfaces of structures and components, from which borated water may have leaked. The Boric Acid Corrosion program includes systematic measures to ensure that corrosion caused by leaking borated coolant does not lead to degradation of the leakage source or adjacent structures or components." However, the applicant should address the following:

1. Electrical components on which borated reactor water may leak onto should be inspected as required by NUREG-1801, Section XI.M10. This should be included in the LRA and FSAR supplement or provide justification for concluding that boric acid corrosion is not an aging effect.

2. Some components and structures that are not adjacent to the leakage source may still be targets of the borated water. Therefore, this AMP should reflect that targets include adjacent systems and components to the leakage source and systems and components that may be leaked on, such as components that are spatially under the leakage source, yet are not directly adjacent to the source.

Dominion Response:

Section B2.1.3 of the LRA states that the Boric Acid Corrosion program is consistent, without exception, with NUREG-1801, Section XI.M10 "Boric Acid Corrosion."

1. Design features, as detailed in Table 3.6.1, Item Number 3.6.1-05, provide physical protection and prevent the corrosion of the connector contact surfaces caused by intrusion of borated water, so this is not an aging effect requiring management. Even though electrical components do not have aging effects that require management, the Boric Acid Corrosion program uses visual inspections to detect the boric acid leakage source, path, and any targets of the leakage. Electrical components are potential targets of boric acid leakage. Therefore, consistent with NUREG-1801, Section XI.M10, boric acid leakage onto electrical components is included in these inspections.

2. Boric Acid Corrosion Program uses visual inspections to detect the boric acid leakage source, path, and any targets of the leakage. This program inspects the surfaces of structures and components from which the borated water may have leaked, and confirms whether degradation has occurred for any potential targets of the identified leakage. In determining the path of boric acid leakage, the applicable adjacent systems and components are identified, as well as

systems and components that are spatially located under the leakage and which may have become targets of the leakage.

Because the program is consistent with the NUREG, the Program Description in Appendix B only provides an overview of the program. To clarify the scope of the program, the second sentence of the Program Description should have read "The Boric Acid Corrosion Program uses visual inspections to detect the boric acid leakage source, path, and any targets of the leakage. This ensures that boric acid corrosion is consistently identified, documented, evaluated, trended, and SSCs are effectively repaired."

The program descriptions in Appendix A, "FSAR Supplement", are intended to provide a summary description of the aging management program and program acceptance criteria. The Boric Acid Corrosion program description is consistent with this intent. To clarify the scope of the program, the following will be inserted after the first sentence of Unit 2 Section A2.1.3 and Unit 3 Section A2.1.2:

> "The program uses visual inspections to detect the boric acid leakage source, path, and any targets of the leakage."

RAI B2.1.17-1

Appendix A, Table A6.0-1 and Appendix B, AMP B2.1.17 of the LRA states that Millstone will follow the industry efforts on reactor vessel internals regarding such issues as thermal or neutron irradiation embrittlement (loss of fracture toughness), void swelling, stress corrosion cracking (PWSCC and IASCC), and loss of pre-load and will implement the appropriate recommendations resulting from this guidance prior to the period of extended operation. Appendix A, Table A6.0-1 provides the applicant's commitments to manage these aging effects, except fro [for] loss of preload. The staff requests that: (1) the applicant formally make a commitment to submit these four programs for NRC review and approval no later than three years prior to the period of extended operation, (2) the applicant include this commitment in the Millstone Units 2 and 3 LRA commitment tracking systems, and (3) include loss of preload in Table A6.0-1 of Appendix A of the LRA.

Dominion Response:

1. The LRAs for Millstone Units 2 and 3 (Appendix A, Table A6.0-1, commitment 13) identify that Millstone will follow the industry efforts on reactor vessel internals regarding such issues as thermal or neutron irradiation embrittlement (loss of fracture toughness), void swelling, stress corrosion cracking (PWSCC and IASCC), and for the Millstone Unit 3 commitment only, loss of pre-load for the baffle and former-assembly bolts (See Item 3 below). Dominion provided a supplemental response applicable to commitment 13 for both Millstone Units 2 and 3 as documented in the Dominion letter (Serial Number 04-320) dated July 7, 2004 (Audit Item Number 6). The supplemental response letter identifies that the statement, "The revised program description, including a comparison to the 10 program elements of the NUREG-1801 program, will be submitted to the NRC for approval." will be inserted at the end of the commitment. Appendix A, Table A6.0-1 for both the Unit 2 LRA and the Unit 3 LRA already states that commitment 13 is scheduled to be completed prior to the period of extended operation. The supplemental response letter also identifies the other applicable locations in both the Unit 2 LRA and the Unit 3 LRA where this additional wording will be inserted.

2. As part of Millstone's normal commitment tracking process, Commitment 13 (Appendix A, Table A6.0-1) for both the Millstone Unit 2 LRA and the Unit 3 LRA, regarding the Inservice Inspection Program: Reactor Vessel Internals, will be included in the commitment tracking system for Millstone Units 2 and 3.

3. For both Millstone Units 2 and 3, loss of pre-load is an applicable aging effect that is managed by the Inservice Inspection: Reactor Vessel Internals Program for bolting used in the reactor vessel. The Millstone Unit 3 LRA (Appendix A, Table A6.0-1, Commitment 13) identifies that Millstone will follow the industry efforts on the loss of pre-load issue for baffle and former-assembly bolts. This issue is applicable to Millstone Unit 3 only. Loss of pre-load was not included in Commitment 13 for Millstone Unit 2 as the baffle and former-assembly is not a bolted configuration, and the issue does not apply.

RAI B2.1.17-2

Appendix B, AMP B2.1.17 of the LRA states that augmented inspection of the Millstone Unit 3 core barrel holddown spring will be performed prior to the period of extended operation. Provide the type of inspections to be performed, inspection frequency and acceptance criteria along with a discussion on why these inspections, their frequencies and inspection criteria will be effective in managing the aging effects specified in Table 3.1.2-2 of the LRA for the holddown spring.

Dominion Response:

At present, the exact examination method, acceptance criteria and frequency are in the process of being determined. As stated in commitment 14 of Table A6.0-1, the chosen inspection method will detect gross indication of loss of preload as an aging effect and be performed prior to the period of extended operation. As an alternative to performing an augmented inspection, the holddown spring may be replaced prior to the period of extended operation. Therefore, for the commitment regarding the Millstone Unit 3 core barrel holddown spring, the wording "As an alternative to performing an augmented inspection, the holddown spring will be replaced prior to the period of extended operation." will be inserted at the end of the commitment. This commitment appears in the LRA for Millstone Units 2 and 3 in the following locations:

- Unit 2, Appendix B, Section B2.1.17 (page B-73)
- Unit 3, Appendix B, Section B2.1.17 (pages B-73, B-74)

This supplemental wording will also be included in the LRA, Appendix A, "FSAR Supplement", in the following locations:

- Unit 3, Appendix A, Section A2.1.16 (page A-14)
- Unit 3, Appendix A, Table A6.0-1, Commitment 14 (page A-35)

RAI B2.1.18-1 (Unit 2)

License renewal commitment Item 14 in Appendix A, Table A6.0.1 states that "Millstone will follow the industry efforts investigating the aging effects applicable to nickel-based alloys (i.e., PWSCC in Alloy 600 base metal and Alloy 82/182 weld metals) and identifying the appropriate aging management activities and will implement the appropriate recommendations resulting from this guidance."

The applicant's commitment needs to reflect that the industry guidance will become part of the applicants aging management program. The applicant is requested to modify commitment Item 1 to state that the aging management activities to monitor the aging effects of nickel based alloys will be submitted three years prior to the period of extended operation in order for staff review and approval to determine if the program demonstrates the ability to manage the effects of aging in nickel based components per 10 CFR 50.54.21(a)(3).

In addition, the applicant needs to address how nickel based components will be evaluated in terms of susceptibility to PWSCC.

Dominion Response:

For the commitment (Item 14) regarding Inservice Inspection Program: Systems, Components and Supports, and Steam Generator Structural Integrity, the wording "The revised program description will be submitted prior to the period of extended operation for staff review and approval to determine if the program demonstrates the ability to manage the effects of aging in nickel based components per 10 CFR 50.54.21(a)(3)." will be inserted at the end of the commitment. This commitment appears in the Unit 2 LRA in the following locations:

- Unit 2 Appendix A, Section A2.1.18 (page A-17)
- Unit 2 Appendix A, Section A2.1.22 (page A-20)
- Unit 2 Appendix A, Table A6.0-1, Commitment 14 (page A-37)
- Unit 2 Appendix B, Section B2.1.18 (page B-75)
- Unit 2 Appendix B, Section B2.1.22 (page B-95)

RAI B2.1.18-1 (Unit 3)

License renewal commitment Item 15 in Table A6.0-1 states that "Millstone will follow the industry efforts investigating the aging effects applicable to nickel-based alloys (i.e., PWSCC in Alloy 600 base metal and Alloy 82/182 weld metals) and identifying the appropriate aging management activities and will implement the appropriate recommendations resulting from this guidance."

The applicant's commitment needs to reflect that the industry guidance will become part of the applicants aging management program. The applicant is requested to modify commitment Item 15 to state that the aging management activities to monitor the aging effects of nickel based alloys will be submitted three years prior to the period of extended operation in order for staff review and approval to determine if the program demonstrates the ability to manage the effects of aging in nickel based components per 10 CFR 50.54.21(a)(3).

In addition, the applicant needs to address how nickel based components will be evaluated in terms of susceptibility to PWSCC.

Dominion Response:

For the commitment (Item 15) regarding Inservice Inspection Program: Systems, Components and Supports, and Steam Generator Structural Integrity, the wording "The revised program description will be submitted prior to the period of extended operation for staff review and approval to determine if the program demonstrates the ability to manage the effects of aging in nickel based components per 10 CFR 50.54.21(a)(3)." will be inserted at the end of the commitment. This commitment appears in the Unit 3 LRA in the following locations:

- Unit 3 Appendix A, Section A2.1.17 (page A-16)
- Unit 3 Appendix A, Section A2.1.21 (page A-19)
- Unit 3 Appendix A, Table A6.0-1, Commitment 15 (page A-36)
- Unit 3 Appendix B, Section B2.1.18 (page B-75)
- Unit 3 Appendix B, Section B2.1.22 (page B-95)

RAI B2.1.18-2 (Unit 2)

Discuss any preventative actions that will be taken for components made of nickel-based alloys to prevent aging effects or mitigate aging degradation. The NRC staff notes that several preventive actions and common industry practices have been used to mitigate PWSCC associated with nickel based alloys. Examples include: nickel plating of the surfaces of nickel-based components that are exposed to treated water, replacement of leaking nickel-based alloy nozzles with Alloy 690 material, preventive replacement of selected pressurizer and RCS nozzles with Alloy 690 material, monitoring the electrochemical potential, and chemistry control. Provide a description of any preventive actions that are planned to address the Alloy 600 cracking issue.

Dominion Response:

As stated in commitment Item 14 in Appendix A, Table A6.0.1 (and as amended in response to RAI B2.1.18-1), Millstone will follow the industry efforts investigating the aging effects applicable to nickel-based alloys (i.e., PWSCC in Alloy 600 base metal and Alloy 82/182 weld metals) and identifying the appropriate aging management activities and will implement the appropriate recommendations resulting from this guidance prior to the period of extended operation. [The revised program description will be submitted prior to the period of extended operation for staff review and approval to determine if the program demonstrates the ability to manage the effects of aging in nickel based components per 10 CFR 50.54.21(a)(3).]

The Millstone License Renewal Application, Appendix B, Section B2.1.3 includes examples of operating experience related to Alloy 600 issues. This Section includes a description of the Millstone Unit 2 and 3 vessel head examinations and repairs related to NRC correspondence on this issue. In letter B18853, "Request for Relaxation from Section IV.C(a)(1) of the Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads", from David A. Christian, Attachment 1, page 4, Dominion acknowledges its intention to replace the reactor vessel head for Millstone Unit 2. The new vessel head package will use improved materials and the new insulation design will better facilitate future examinations.

This section also describes the ISI visual inspection of the pressurizer heater penetrations for Millstone Unit 2, and the corresponding design change that was generated to address the issue by installing mechanical nozzle seal assembly (MNSA) clamps on the leaking heater penetrations to prevent leaking. The mechanical nozzle seal assembly clamp is a Westinghouse designed alternative replacement for repair of leaking nozzles. As identified in the response to Request item 107 from the AMP/AMR Audit conducted the week of May 3, 2004, and in a letter from Ms. Leslie N. Hartz, Dominion Nuclear Connecticut, to U. S. Nuclear Regulatory Commission, dated June 3, 2004, Dominion announced its intention to replace the pressurizer for Millstone Unit 2 using materials that are less susceptible to PWSCC.

RAI B2.1.18-2 (Unit 3)

Discuss any preventative actions that will be taken for components made of nickel-based alloys to prevent aging effects or mitigate aging degradation. The NRC staff notes that several preventive actions and common industry practices have been used to mitigate PWSCC associated with nickel based alloys. Examples include: nickel plating of the surfaces of nickel-based components that are exposed to treated water, replacement of leaking nickel-based alloy nozzles with Alloy 690 material, preventive replacement of selected pressurizer and RCS nozzles with Alloy 690 material, monitoring the electrochemical potential, and chemistry control. Provide a description of any preventive actions that are planned to address the Alloy 600 cracking issue.

Dominion Response:

As stated in commitment Item 15 in Appendix A, Table A6.0.1 (and as amended in response to RAI B2.1.18-1), Millstone will follow the industry efforts investigating the aging effects applicable to nickel-based alloys (i.e., PWSCC in Alloy 600 base metal and Alloy 82/182 weld metals) and identifying the appropriate aging management activities and will implement the appropriate recommendations resulting from this guidance prior to the period of extended operation. [The revised program description will be submitted prior to the period of extended operation for staff review and approval to determine if the program demonstrates the ability to manage the effects of aging in nickel based components per 10 CFR 50.54.21(a)(3).]

The Millstone License Renewal Application, Appendix B, Section B2.1.3 includes examples of operating experience related to Alloy 600 issues. This Section includes a description of the Millstone Unit 2 and 3 vessel head examinations and repairs related to NRC correspondence on this issue. In letter B18853, "Request for Relaxation from Section IV.C(a)(1) of the Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads", from David A. Christian, Attachment 1, page 4, Dominion acknowledges its intention to replace the reactor vessel head for Millstone Unit 2. The new vessel head package will use improved materials and the new insulation design will better facilitate future examinations.

This section also describes the ISI visual inspection of the pressurizer heater penetrations for Millstone Unit 2, and the corresponding design change that was generated to address the issue by installing mechanical nozzle seal assembly (MNSA) clamps on the leaking heater penetrations to prevent leaking. The mechanical nozzle seal assembly clamp is a Westinghouse designed alternative replacement for repair of leaking nozzles. As identified in the response to Request item 107 from the AMP/AMR Audit conducted the week of May 3, 2004, and in a letter from Ms. Leslie N. Hartz, Dominion Nuclear Connecticut, to U. S. Nuclear Regulatory Commission, dated June 3, 2004, Dominion announced its intention to replace the pressurizer for Millstone Unit 2 using materials that are less susceptible to PWSCC.

RAI B2.1.18-3

Table 3.1.2-1 of the Millstone, Unit 3 LRA identifies the BMI Flux Thimble Tubes and BMI Guide Tubes as being susceptible to cracking from SCC. The aging management programs in the LRA for cracking of the BMI Flux Thimble Tubes and BMI Guide Tubes are the Water Chemistry AMP and AMP B2.1.18, "Inservice Inspection Program: Systems, Components and Supports" of the LRA. However, the thimble tube inspections discussed in AMP B2.1.18 were initially designed to inspect for wear in the thimble tubes and NUREG-1801, section IVB2.6-a requires the use of the PWR Vessel Internals AMP to manage cracking in the guide tubes. Details of these inspections including scope, examination method, acceptance criteria, and examination frequencies are not included in AMP B2.1.18 of the LRA. Since the outside diameter surface of the thimble tubes is exposed to the same environment as the inside diameter surface of the guide tube and both components are fabricated from stainless steel, they would both be susceptible to SCC. Therefore, provide the types of inspections that will be performed to manage cracking in the thimble and guide tubes, along with a discussion on why these inspections, their frequency and inspection criteria will be effective in managing cracking. The operating experience of cracking in these tubes and any resulting replacements should also be provided.

Dominion Response:

Although the thimble tubes are inserted into the core, the BMI Flux Thimble Tubes and the BMI Guide Tubes identified in Unit 3 LRA Table 3.1.2-1 are not reactor vessel internals components and the Inservice Inspection Program: Reactor Vessel Internals AMP is not applicable for management of the associated aging effects for these components.

The BMI flux thimble tubes (corresponding to NUREG-1801 item IV.B2.6.2) are the in-core flux detector thimble tubes and are the subcomponents that are inserted and extracted from the core area through the 58 reactor vessel bottom head penetrations. The 5/16" OD BMI flux thimble tubes are exposed to reactor coolant pressure externally and are loaded in compression in service. This compressive load combined with the small surface area does not result in a significant stress component for SCC to occur in the BMI flux thimble tubes. However, cracking due to SCC has been conservatively applied as an aging effect to the BMI flux thimble tubes. Aging management for cracking is provided by the Chemistry Control for Primary Systems Program AMP in order to minimize potential contaminants. Additional aging management is provided by crediting the existing inspection of the seal table pressure boundary during each refueling outage via the Inservice Inspection Program: Systems, Components, and Supports AMP.

The BMI guide tubes (no corresponding NUREG-1801 item) are the guide tubes in which the BMI flux thimble tube travels. The stainless steel BMI guide tubes extend from the seal table to the nickel-based alloy instrument tubes that are attached to the reactor vessel bottom head. This configuration results in a significant temperature reduction in the BMI guide tubes from RCS operating temperature, which greatly reduces

susceptibility of the stainless steel material to SCC. Based on service temperature, the most susceptible location for cracking due to SCC in the BMI guide tubes is the interface weld between the BMI guide tubes and the reactor vessel nozzle, identified as Instrumentation Tubes (bottom head) in Table 3.1.2-1. This weld is inspected as part of the Inservice Inspection Program: Systems, Components, and Supports AMP and provides a leading indicator for BMI guide tube cracking. The reduced temperature, along with control of contaminants provided by the Chemistry Control for Primary Systems Program AMP, reduces the potential for stress corrosion cracking of the BMI guide tubes.

There have been no instances of cracking found in the Millstone Unit 3 BMI flux thimble tubes or the BMI guide tubes.

RAI B2.1.18-4

Table 3.1.2-2 of the LRA states AMP B2.1.17, "Reactor Vessel Internals," will be used to manage loss of preload/stress relaxation for the clevis insert bolts, upper support column bolts and the lower support plate column bolts. However, NUREG 1801, sections IVB2.1-k, IVB2.5-i, and IVB2.5-h, requires loss of preload to be managed by the AMP XI.M1, "ASME Section XI Inservice Inspection," which correlates to the applicant's AMP B2.1.18, "Inservice Inspection Program: Systems, Components and Supports." In addition, the applicant's AMP B2.1.17, has no requirements for bolts other than former/baffle bolts. Therefore, the applicant is requested to specify the correct AMP as required by NUREG-1801 or provide the necessary information in AMP B2.1.17.

Dominion Response:

The Inservice Inspection Program: Reactor Vessel Internals AMP includes the requirements of examination category B-N-3 of the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWB, as described in LRA Appendix B, Section B2.1.17. Category B-N-3 in Table IWB-2500-1 of the Code includes examination requirements for removable core support structures (i.e., reactor vessel internals) including the clevis insert bolts, the upper support column bolts, and the lower support plate column bolts. These examinations are identical to those cited in NUREG-1801, Section XI.M1 "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for the reactor core support structures (page XI M-4).

RAI B2.1.18-5

GALL indicates that reactor head closure studs are susceptible to loss of material due to wear and to crack initiation and growth due to stress corrosion cracking (SCC). GALL recommends Chapter XI.M3, "Reactor Head Closure Studs" program as a program acceptable for mitigating and monitoring these aging effect. This program relies on ASME Code Section XI, Subsection IWB to monitor and detect this aging effect. Preventive measures identified in the NUREG-1801 program include avoiding the use of metal-plated stud bolting to prevent degradation due to corrosion or hydrogen embrittlement and using manganese phosphate or other acceptable surface treatments and stable lubricants (RG 1.65). Provide the operating experience of the reactor vessel closure studs, including the use of coatings or lubrication, and what degradation, if any, that was found during these inspections with the corresponding corrective actions.

Dominion Response:

As identified in the Inservice Inspections: Systems, Components, and Supports Aging Management Program, both Millstone Units 2 and 3 follow the recommendations of Regulatory Guide 1.65 as follows:

Millstone Unit 2 uses ASME SA 540, Grade B-24 as the material for the vessel studs, with a manganese phosphate coating on the studs. ASTM A 540, Grade B-23 material is used for the reactor vessel closure nuts and washers, and "parkerizing" (manganese phosphate) is the specified coating. The bolting is lubricated at installation with Fel-Pro N-5000, a nickel-based, anti-seize lubricant, which can be used in applications with a dry surface temperature as high as 2400 degrees F.

For Millstone Unit 3, the reactor vessel closure bolting is fabricated from ASME SA-540 material. The closure studs are Grade B-24 material and the nuts and washers are Grade B-23 material. A phosphate coating is applied to the bolting. In accordance with a design modification, the threaded portions of the studs have a PlasmaBond coating applied in lieu of the original phosphate coating. PlasmaBond is a Nickel-Silver/Palladium coating using a vapor deposition process that eliminates the potential for hydrogen embrittlement. This newer anti-galling coating was added to provide for lubrication, and has no adverse metallurgical interactions. This coating is fully endorsed by Westinghouse for use on vessel head closure studs. Application of Fel-Pro N-5000 is not needed when vessel closure studs have been PlasmaBond coated.

As recommended by Regulatory Guide 1.65, plugs are installed in the empty stud hole cavities following stud removal during refueling for both Millstone Units 2 and 3 in order to provide protection against contamination and corrosion. Nondestructive examinations are performed to comply with the requirements of ASME Section XI, Subsection IWB. To date, no age related degradation has been identified for the vessel closure bolting for either Millstone Unit.

RAI B2.1.18-6

The applicant states in section B2.1.18 of Appendix B of the LRA that the potential for thermal aging embrittlement of CASS components is addressed through the performance of plant-specific or component-specific evaluations in accordance with section XI.M12 of NUREG-1801, to assess whether the material has adequate fracture toughness. This is consistent with the NUREG-1801 screening for susceptibility to thermal aging embrittlement of CASS piping. NUREG-1801 does not require additional inspections beyond those required by the ASME Code for pump casings and valve bodies and the ASME Code Case N-481 for pump casings. If CASS piping is not susceptible, then no additional inspections are required. However, susceptible CASS piping is required to be inspected by an enhanced volumetric examination to detect and size cracks. Therefore, the applicant is requested to update the AMP to include the necessary inspections required by NUREG-1801 for CASS piping that are found to be susceptible (inadequate fracture toughness).

Dominion Response:

The following information will be added to the Inservice Inspection Program: Systems, Components and Supports Aging Management Program:

"For potentially susceptible CASS materials, either enhanced volumetric examinations or a unit specific flaw tolerance evaluation considering reduction in fracture toughness and using specific geometry and stress information will be used to demonstrate that the thermally embrittled material has adequate toughness in accordance with NUREG-1801 "Generic Aging Lessons Learned (GALL) Report", Section XI.M12, April 2001. This commitment is identified in the FSAR Supplement, Table A6.0-1 License Renewal Commitments, Item 27 (Unit 2) and Item 28 (Unit 3)."

RAI B2.1.18-7 (Unit 2)

Table 3.1.2-3 of the LRA specifies AMP B2.1.18, "Inservice Inspection Program," to manage cracking of the nickel-based pressurizer heater sheathes and sleeves. However, AMP B2.1.18 does not provide specific information on these components. However, Appendix B, AMP B2.1.3, "Boric Acid Corrosion," of the LRA states that during ISI visual inspection of the nickel-based pressurizer heater penetrations for Millstone Unit 2, two penetrations were found to be leaking through cracks. A design change was generated to address the issue by installing mechanical nozzle seal assembly (MNSA) clamps on the leaking heater penetrations to prevent leaking. However, MNSAs are currently not considered long term repairs, in particular for the extended period of operation, without providing justification, which includes an analysis of the pressure boundary component and an inservice inspection program to be maintained throughout the licensed life of the plant. As required by a NRC letter dated December 8, 2003, to the Westinghouse Owners Group, the analysis and inservice inspection program requires NRC approval. Therefore, provide the required information, set forth in the December 8, 2003, letter to justify the continued approval of the MNSAs for the period of extended operation. This information should also include corrective actions, such as weld repairs, half-nozzle repairs or pressurizer replacements that may be performed in the future to eliminate the MNSAs. This information should then be included in AMP B2.1.18 which manages cracking of the pressurizer penetrations.

Dominion Response:

As identified in letter S/N 04-140 from Ms. Leslie N. Hartz, Dominion Nuclear Connecticut, to U. S. Nuclear Regulatory Commission, dated June 3, 2004; Dominion announced its intention to replace the pressurizer for Millstone Unit 2 using materials that are resistant to PWSCC. Dominion intends to replace the Unit 2 pressurizer during the Fall 2006 refueling outage.

RAI B2.1.18-8

Table 3.1.2-1 of the LRA specifies AMP B2.1.18, "Inservice Inspection Program: Systems, Components and Supports," to manage loss of material due to wear for the BMI flux thimble tubes. This AMP specifies that as a result of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," Millstone Unit 3 actively manages incore thimble tube degradation through performance of eddy current testing during each refueling outage. To determine the acceptability of this AMP, as required by NUREG-1801, section IV B2.6-c, the acceptance criterion, with technical justification, e.g., percent through-wall loss, and wear scar geometry uncertainty is required to be submitted. In addition, provide the scope (the number of total tubes and the percent of tube inspected) of the eddy current inspection and the operating experience concerning wear of the thimble tubes at Millstone, Unit 3.

Dominion Response:

The structural acceptance criterion for the Millstone Unit 3 BMI flux thimble tubes is 80% wall thinning, as determined by current and previous readings conservatively projected to the time of the next inspection. The 80% acceptance figure includes significant margins against structural failure, and is based on evaluations and testing documented in Westinghouse proprietary report WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear", dated January 1991. Thimbles that do not meet the acceptance standards are either capped or replaced. The eddy current calibration standard includes the most severe wear scar geometries, such that readings of actual flaws with less severe geometry are conservative. Therefore no adjustment for postulated wear scar geometry is required. Although the WCAP states that " ... it is not necessary to add additional uncertainty margin to the eddy current wall loss indications...", an instrument uncertainty of 3% is assumed. This value is conservative based on the scatter in data observed at Millstone for highly worn thimbles.

There are a total of 58 BMI flux thimble tubes and currently 100% inspection is performed each outage. The frequency of future inspections may be adjusted, for example, if highly worn tubes are replaced with wear resistant material and the remaining thimbles can be shown to meet acceptance criteria for multiple cycles. To date, fourteen BMI flux thimble tubes have been repositioned and four have been capped because they might not have met the acceptance criterion at the next inspection.

RAI B2.1.20-1

The applicant's AMP, section B2.1.20 of Appendix B to the LRA, and the FSAR supplement provides a general description of the reactor vessel surveillance program (RVSP) for Millstone Units 2 and 3. However, 10 CFR Part 50, Appendix H, requires licensees to submit any proposed changes to their RVSP withdrawal schedules to the NRC for review and approval. In addition, Items 5 through 7 in NUREG-1801, section XI.M31, "Reactor Vessel Surveillance," provide recommendations for withdrawal of capsules during the period of license renewal. Provide the following information to confirm that the applicant's surveillance program meets the requirements of NUREG-1801:

1) Items 5 through 7 in NUREG-1801, AMP XI.M31 provide recommendations for withdrawal of capsules during the period of license renewal. The staff requested that the applicant identify how the Millstone, Units 2 and 3, capsule withdrawal schedule for the period of license renewal complies with Items 5 through 7 in NUREG-1801, AMP XI.M31.

2) For reactor vessels with high lead factors, the standby capsules are required by NUREG-1801, AMP XI.M31 to be removed and placed in storage. What are the lead factors for Millstone, Units 2 and 3? If the Millstone units have high lead factors, how are these capsules stored to ensure that they are not disposed?

Dominion Response:

1. Consistent with NUREG-1801, Aging Management Program (AMP) XI.M31, Item 5, Dominion will revise the surveillance capsule withdrawal schedule from 40 to 60 years (54 EFPY) for Millstone Unit 2. Consistent with NUREG-1801, AMP XI.M31, Item 5, the schedule will include withdrawal and testing of at least one of the three remaining capsules during the period of extended operation. Consistent with NUREG-1801, AMP XI.M31, Item 7, if Dominion withdraws the last Millstone Unit 2 capsule prior to year 55, Dominion will provide additional dosimetry for the reactor pressure vessel.

   The Millstone Unit 3 surveillance program consists of capsules with a projected fluence exceeding the 60-year fluence at the end of 40 years. In accordance with NUREG-1801, AMP XI.M31, Item 6, Millstone Unit 3 will withdraw the remaining capsule (capsule W) when the capsule receives neutron fluence equivalent to 60-year fluence (approximately 54 EFPY). This capsule will be tested in accordance with the requirements of ASTM E 185. There are three standby capsules that will also be removed prior to the capsules receiving neutron fluence equivalent to 60-year fluence. One of these may be selected to remain in place for the purpose of flux monitoring, but will be over-irradiated in terms of meaningful metallurgical information. If Dominion withdraws the last Millstone Unit 3 capsule prior to year 55, Dominion will establish and maintain the Millstone Unit 3 neutron irradiation

environment that is applicable to the surveillance data and Pressure-Temperature Limits. Consistent with NUREG-1801, AMP XI.M31 (last paragraph), if the reactor pressure vessel operates outside these limits, Dominion will inform the NRC and determine the impact of the condition on the reactor pressure vessel integrity. Consistent with NUREG-1801, AMP XI.M31, Item 7, if Dominion withdraws the last Millstone Unit 3 capsule prior to year 55, Dominion will provide additional dosimetry for the reactor pressure vessel.

2. For Millstone Unit 2, the lead factors for the remaining surveillance capsules are approximately 1 (0.97 to 1.31).

   For Millstone Unit 3, the lead factors for the remaining surveillance capsules are approximately 4 (4.11 to 4.32).

   Removed standby capsules will be placed in storage for potential reuse should supplemental information be needed. Storage of irradiated components in the spent fuel pool is administratively controlled by unit specific procedures.

RAI B2.1.22-1

On page B-95 of the Unit 2 LRA and page B-96 of the Unit 3 LRA, the applicant states: "The Steam Generator Structural Integrity program does not require enhancement to be consistent with the aging management program described in NUREG-1801, Section XI.M20, "Open Cycle Cooling Water System." However, Section XI.M20 of NUREG-1801 does not make any reference to Section XI.M19, "Steam Generator Tube Integrity." The staff requests the applicant to clarify this statement.

Dominion Response:

In Section B2.1.22 (on page B-95 of the Unit 2 LRA and page B-96 of the Unit 3 LRA), the program description should say, "The *Steam Generator Structural Integrity* program does not require enhancement to be consistent with the aging management program described in NUREG-1801, Section XI.M19, *Steam Generator Tube Integrity Program.*"

RAI B2.1.22-2

Table 3.1.2-4, the applicant identifies the GALL steam generator AMP, XI.M19 as the AMP to manage the aging effect loss of material in the tube sheet (and cladding) for both units. The GALL steam generator AMP, XI.M19, does not address the steam generator tube sheet (and cladding). Therefore, the applicant must provide details for the following aging management program attributes for this component: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria.

In addition, the staff requests:

1. The applicant to provide design information regarding their steam generators (i.e., tube manufacturer, tube spacing, tube support material, etc.)

2. The applicant to provide more recent information regarding the operating experience of their steam generators.

Dominion Response:

The Steam Generator Structural Integrity Program is an existing program that is consistent with NUREG-1801, Section XI.M19, "Steam Generator Tube Integrity Program." Although the scope of the NUREG-1801 program only addresses the steam generator tubes, the Steam Generator Structural Integrity Program for Millstone Units 2 and 3 additionally addresses the secondary side of the steam generator tube sheet. The aging management program attributes for the uncladded secondary side of the tube sheet: Preventive Actions; Parameters Monitored/Inspected; Detection of Aging Effects; Monitoring and Trending; and Acceptance Criteria are as follows:

Preventive Actions:

The *Chemistry Control for Secondary Systems* aging management program, B2.1.6, includes the necessary mitigative activities to maintain secondary-side water chemistry so that it is compatible with the tube sheet materials exposed to secondary system fluid. For the secondary side of the tube sheet, the aging effect to be mitigated through the *Chemistry Control for Secondary Systems* AMP is loss of material.

Parameters Monitored/Inspected:

The *Steam Generator Structural Integrity Program* identifies loss of material as the aging effect for the uncladded secondary side of the tube sheet. The Millstone steam generator inspection procedures include remote and direct visual examination of the tube sheet's accessible areas for apparent degradation.

Detection of Aging Effects:

The *Steam Generator Structural Integrity Program* manages the effects of aging by detecting loss of material as the applicable aging effect prior to loss of intended function. An assessment is performed prior to inspection to determine the expected amount of degradation. Inspection frequencies for the tube sheet are established in accordance with such degradation assessments, and are adjusted as necessary based on comparison of such assessments to actual inspection results.

Monitoring and Trending:

Secondary side tube sheet degradation is evaluated in accordance with the corrective action process to ensure that timely corrective and mitigative actions are performed as necessary. The extent of degradation is monitored and trended to ensure that the intended function is maintained consistent with the current licensing basis during the period of extended operation.

Acceptance Criteria:

The tube sheet is remotely or direct visually inspected for any apparent degradation, which is identified and evaluated in accordance with the corrective action process. The corrective action process provides reasonable assurance that deficiencies adverse to quality are either promptly corrected or are evaluated to be acceptable. Where evaluations are performed without repair or replacement, engineering analysis reasonably assures that the structure or component intended function is maintained consistent with the current licensing basis during the period of extended operation.

Attachment 2

Supplemental Request for Additional Information Response

Millstone Power Station Units 2 & 3
Dominion Nuclear Connecticut, Inc.

RAI 2.1-1

Based on a review of the LRA, the applicant's scoping and screening implementation procedures, and discussions with the applicant, the staff determined that additional information is required with respect to certain aspects of the applicant's evaluation of the 10 CFR 54.4(a)(2) criteria. Please address the following:

A. Section 2.1.3.6, "10CFR54.4(a)(2) Report," of the LRA, and the applicant's technical report prepared to address the (a)(2) issue, state that NSR piping that is attached to SR piping, and that is seismically designed and supported *up to* (emphasis added) the first equivalent anchor point beyond the SR/NSR boundary, is included within the scope of license renewal. However, NUREG-1800, Section 2.1.3.1.2, states that the scoping methodology includes both the NSR piping *and the associated piping anchors* (emphasis added) as being within the scope of license renewal pursuant to 10 CFR 54.4(a)(2).

   Based on the above, the staff requests that the applicant define the term "first equivalent anchor point" as it relates to the evaluation of NSR piping attached to SR piping and describe the methodology of its application. In cases where plant equipment credited with providing support to NSR piping within the scope of license renewal may be equivalent to an associated piping anchor as described in NUREG-1800, provide justification for not including this plant equipment within the scope of license renewal.

B. Describe the methodology and documentation sources used to perform walkdowns associated with the review of NSR fluid-containing components located near SR components (spatial interaction). Additionally, for low energy fluid-containing NSR components, describe the extent to which engineering judgment was used to identify NSR components, which may affect SR components.

Dominion Response:

Dominion responded to this RAI by letter dated November 9, 2004 (Serial No. 04-673). The original response is not duplicated here due to its large volume. The following information does not alter the content of the original response but does provide additional detail as requested by the staff in a telephone call held between the NRC and Dominion on November 9, 2004.

Supplemental Information:

In the November 9, 2004 telephone call, the staff requested that the response to RAI 2.1-1, provided in Dominion letter SN 04-637, dated November 9, 2004, be supplemented to provide a list of component types associated with systems whose license renewal boundaries were expanded as a result of the response to RAI 2.1-1.

Also, provide a brief description of the systems added to the scope of license renewal in response to RAI 2.1-1. Additionally, by email dated 11/29/2004, the staff requested clarification regarding the usage of the intended functions LSI and PB as they relate to the criteria of 10CFR54.4(a)(2).

The following is a list of component types, with their associated intended functions, that were added to the scope of license renewal for in-scope systems as a result of the response to RAI 2.1-1. The LRA screening results table for each system is provided as a reference.

Millstone Unit 2

Engineered Safety Features Systems:

- Refueling Water Storage Tank and Containment Sump (LRA Table 2.3.2-3)
  - RWST Heat Exchangers (LSI)
  - RWST Circulating Pump (LSI)

- Spent Fuel Pool Cooling (LRA Table 2.3.2-5)
  - Filters (LSI)
  - Mixing Tank (LSI)

Auxiliary Systems:

- Access Control Area Air Conditioning (LRA Table 2.3.3-13)
  - Access Control Area A/C Unit (LSI)

- Chilled Water (LRA Table 2.3.3-6)
  - Non-Vital Chiller (LSI)

- Clean Liquid Waste Processing (LRA Table 2.3.3-38)
  - Conductivity Element (PB, LSI)
  - Degasifiers (PB, LSI)
  - Degasifier Vent Condenser (PB, LSI)
  - Equipment Drain Sump Tank (PB, LSI)
  - Flexible Hose (PB, LSI)
  - Flow Indicators (PB, LSI)

- Domestic Water (LRA Table 2.3.3.33)
  - Domestic Water Hot Water Tank (PB, LSI)

- Instrument Air (LRA Table 2.3.3-7)
  - Compressors (PB, LSI)
  - Compressor Aftercoolers (PB, LSI)
  - Containment Instrument Air Receiver Tank (LSI)

- Main Condensers Evacuation (LRA Table 2.3.3-14)
  - Flow Orifices (PB, LSI)
  - Flow Switch (PB, LSI)
  - Filter/Strainer (PB, LSI)
  - Steam jet Air Ejector Vent Condenser (LSI)

- Nitrogen (LRA Table 2.3.3-8)
  - Flow Indicators (LSI)

- Primary Makeup Water (LRA Table 2.3.3-12)
  - Make-up Water Vacuum Dearator (PB, LSI)
  - Primary Water Storage Tank (PB, LSI)
  - Dearator Water Transfer Pump (PB, LSI)

- Sampling (LRA Table 2.3.3-11)
  - Sample Chiller (PB, LSI)
  - Secondary Sample Station/Sink (LSI)

- Station Air (LRA Table 2.3.3-9)
  - Compressors (PB, LSI)
  - Air Compressor Aftercoolers (PB, LSI)
  - Air Compressor Intercoolers (PB, LSI)

- Station Sumps and Drains (LRA Table 2.3.3-41)
  - Collection Section Tank (PB, LSI)
  - Flow Indicators (PB, LSI)
  - Filter (PB, LSI)

Steam and Power Conversion Systems:

- Electro Hydraulic Control (This system is included in Unit 2 LRA Table 2.2-1 as an in-scope system, but previously had no passive mechanical components subject to aging management review. Therefore, there is no existing LRA screening results table.)
  - Filter/Strainers (PB, LSI)
  - Flexible Hoses (PB, LSI)
  - Flow Indicators (PB, LSI)
  - Pipe (PB, LSI)
  - Pumps (PB, LSI)
  - Tubing (PB, LSI)
  - Hydraulic Fluid Coolers (PB, LSI)
  - Valves (PB, LSI)

- Main Steam (LRA Table 2.3.4-1)
  - Steam Generator Blowdown Tank (LSI)

Millstone Unit 3

Engineered Safety Features Systems:

- Fuel Pool Cooling and Purification (LRA Table 2.3.2-5)
  - Fuel Pool Demineralizer (PB, LSI)
  - Fuel Pool Post Filter (PB, LSI)
  - Strainers (PB, LSI)

- Quench Spray (LRA Table 2.3.2-2)
  - Refueling Water Cooler (PB, LSI)

- Safety Injection (LRA Table 2.3.2-3)
  - Hydro Test Pump (LSI)

Auxiliary Systems:

- Boron Recovery (LRA Table 2.3.3-43)
  - Boron Distillate Cooler (PB, LSI)
  - Boron Distillate Tank (PB, LSI)
  - Boron Evaporator (PB, LSI)
  - Boron Evaporator Bottoms Coolant Preheater (PB, LSI)
  - Boron Evaporator Bottoms Cooler (PB, LSI)
  - Boron Evaporator Condenser (PB, LSI)
  - Boron Evaporator Reboiler (PB, LSI)
  - Boron Evaporator Sample Cooler (PB, LSI)
  - Density Element (PB, LSI)
  - Flow Indicating Switch (PB, LSI)
  - Flow Indicating Transmitter (PB, LSI)
  - Flow Transmitters (PB, LSI)
  - Pumps (PB, LSI)
  - Restricting Orifices (PB, LSI)
  - Traps (PB, LSI)

- Chemical and Volume Control (LRA Table 2.3.3-15)
  - Boric Acid Batching Tank (PB, LSI)

- Containment Vacuum (LRA Table 2.3.3-23)
  - Pumps (LSI)
  - Vacuum Ejector (LSI)

- Radioactive Gaseous Waste (LRA Table 2.3.3-45)
  - Degasifier Feed Preheater (PB, LSI)
  - Degasifiers (PB, LSI)
  - Degasifier Condenser (PB, LSI)
    - Tubing (PB, LSI)

- Radioactive Liquid Waste Processing (LRA Table 2.3.3-44)
  - Pumps (PB, LSI)
  - Radiation Detectors (PB, LSI)
  - Tubing (PB, LSI)

- Reactor Plant Aerated Drains (LRA Table 2.3.3-48)
  - Groundwater Underdrains Storage Tank (PB, LSI)

- Reactor Plant Component Cooling (LRA Table 2.3.3-4)
  - Radiation Detectors (PB, LSI)

- Reactor Plant Gaseous Drains (LRA Table 2.3.3-49)
  - Containment Drains Transfer Tank (LSI)
  - Primary Drains Transfer Tank (LSI)

- Reactor Plant Sampling (LRA Table 2.3.3-16)
  - Flow Elements (PB, LSI)
  - Mechanical Refrigeration Unit Condenser (PB, LSI)
  - Mechanical Refrigeration Unit Evaporator/Chiller (PB, LSI)
  - Radiation Detectors (PB, LSI)

- Service Air (LRA Table 2.3.3-14)
  - Flow Transmitters (LSI)

Steam and Power Conversion Systems:

- Auxiliary Boiler Condensate and Feedwater (LRA Table 2.3.4-7)
  - Flow Elements (PB, LSI)
  - Radiation Detectors (PB, LSI)

- Auxiliary Feedwater (LRA Table 2.3.4-2)
  - DWST Heater (PB, LSI)

- Steam Generator Blowdown (LRA Table 2.3.4-4)
  - Steam Generator Blowdown Tank (LSI)

The following are descriptions of the eight systems added to the scope of license renewal in response to RAI 2.1-1.

Aerated Liquid Radwaste

The Aerated Liquid Radwaste System provides controlled handling, processing, monitoring, and disposal of low-level radioactive liquids that are collected by open drains in the plant. It is in the scope of license renewal and meets 10CFR54.4(a)(2) because it is a non-safety, low-energy system that contains components that have been identified to affect a function of a safety-related system due to the proximity of this system to the safety-related system.

Additional details of the Aerated Liquid Radwaste System can be found in the Millstone Unit 2 FSAR, Section 11.1.3.

Solid Waste Processing

The Solid Waste Processing System provides controlled handling, processing, monitoring, and packaging of radioactive spent resins, from demineralizers and ion exchangers, and radioactive filter cartridges generated during plant operation. It is in the scope of license renewal and meets 10CFR54.4(a)(2) because it is a non-safety, low-energy system that contains components that have been identified to affect a function of a safety-related system due to the proximity of this system to the safety-related system.

Additional details of the Solid Waste Processing System can be found in the Millstone Unit 2 FSAR, Section 11.1.5.

Turbine Building Closed Cooling Water

The Turbine Building Closed Cooling Water System is a closed-loop cooling water system that transfers heat from non-safety-related turbine plant components and sample coolers to the Service Water System, via the turbine building closed cooling water heat exchangers. It is in the scope of license renewal and meets 10CFR54.4(a)(2) because it is a non-safety, low-energy system that contains components that have been identified to affect a function of a safety-related system due to the proximity of this system to the safety-related system.

Additional details of the Turbine Building Closed Cooling Water System can be found in the Millstone Unit 2 FSAR, Section 9.7.3.

Water Box Priming

The Water Box Priming System provides a vacuum source for priming the condenser water boxes in order to keep the condenser tubes full of water. It is in the scope of license renewal and meets 10CFR54.4(a)(2) because it is a non-safety, low-energy system that contains components that have been identified to affect a function of a safety-related system due to the proximity of this system to the safety-related system.

Auxiliary Steam Reboiler and Deaerating Feedwater

The Auxiliary Steam Reboiler and Deaerating Feedwater System provides a source of auxiliary steam for house heating loads. It is in the scope of license renewal and meets 10CFR54.4(a)(2) because it is a non-safety, low-energy system that contains components that have been identified to affect a function of a safety-related system due to the proximity of this system to the safety-related system and that contains components that are attached to safety-related piping.

Additional details of the Auxiliary Steam Reboiler and Deaerating Feedwater System can be found in the Millstone Unit 2 FSAR, Section 10.3.1.1.

Exciter Air Cooler

The Exciter Air Cooler System provides air cooling to the main generator exciter and isophase bus duct. Turbine building component cooling water serves as the heat sink for the system. Heat transfer occurs in the isolated phase bus cooler. It is in the scope of license renewal and meets 10CFR54.4(a)(2) because it is a non-safety, low-energy system that contains components that have been identified to affect a function of a safety-related system due to the proximity of this system to the safety-related system.

Additional details of the Exciter Air Cooler System can be found in the Millstone Unit 2 FSAR, Sections 9.7.3.2.1 and 10.2.

Stator Liquid Cooler

The Stator Liquid Cooler System provides a source of cooling to the main generator stator. Turbine building component cooling water serves as the heat sink for the system. It is in the scope of license renewal and meets 10CFR54.4(a)(2) because it is a non-safety, low-energy system that contains components that have been identified to affect a function of a safety-related system due to the proximity of this system to the safety-related system.

Additional details of the Stator Liquid Cooler System can be found in the Millstone Unit 2 FSAR, Section 9.7.3.2.1 and 10.2.

Turbine Lube Oil

The Turbine Lube Oil System provides lubricating oil to the main turbine-generator bearings. It is in the scope of license renewal and meets 10CFR54.4(a)(2) because it is a non-safety, low-energy system that contains components that have been identified to affect a function of a safety-related system due to the proximity of this system to the safety-related system.

Additional details of the Turbine Lube Oil System can be found in the Millstone Unit 2 FSAR, Section 10.2.

Electro Hydraulic Control

The following description is provided for the Electro Hydraulic Control System that, although it is in the scope of license renewal, is not currently described in the Unit 2 LRA:

> The Electro Hydraulic Control (EHC) system provides high-pressure hydraulic fluid for the operation of the main turbine valves. The EHC system provides signals to trip the turbine and provides a signal, which is based on turbine first stage pressure, to the reactor regulating system as a load reference. It is in the scope of license renewal and meets 10CFR54.4(a)(1) because it provides turbine trip signal input to the reactor protection system and 10CFR54.4(a)(2) because it is a non-safety, low-energy system that contains components that have been identified to affect a function of a safety-related system due to the proximity of this system to the safety-related system.
>
> Additional details of the EHC system can be found in the Millstone Unit 2 FSAR, Section 10.2.

The intended function Limited Structural Integrity (LSI) applies to components in the scope of license renewal for 10CFR54.4(a)(2) due to either spatial orientation or non-safety attached to safety-related piping intended functions. The LSI function is combined with the Pressure Boundary (PB) function for components in the scope of license renewal for spatial orientation. In the original response to RAI 2.1-1, Table 5, "Steam and Power Conversion System – Auxiliary Steam Reboiler and Deaerating Feedwater," identifies component types with the intended function of LSI only. These are in the scope of license renewal as non-safety attached to safety-related piping components. Table 5 also contains a component that is in the scope of license renewal due to implementation of the enhanced spatial orientation methodology and has the intended function of LSI and PB. Therefore, the eight new systems identified in the original RAI 2.1-1 response were added to the scope of license renewal based on the enhanced spatial orientation methodology. Although the system in Table 5 does contain components with the intended function of non-safety attached to safety-related piping, no new system was added to the scope of license renewal solely for the non-safety attached to safety-related piping intended function.

RAI 2.3.3.28-1A

2.3.3.28 Process and Area Radiation Monitoring (Unit 2)

LRA Section 2.3.3.28 states that this system is within the scope of license renewal because it meets the requirements of 10 CFR 54.4(a)(1) by providing, among other things, "actuation of certain systems or components in response to detected radiation conditions." In order to perform this function, the section of piping downstream of valves 2-AC-527 and 2-AC-529 serves as a pressure boundary. This section of piping is not shown on license renewal drawing 25203-LR26028, Sheet 2, sections J6 and G6, as being within the scope of license renewal. Clarify whether these components are within the scope of license renewal and subject to an AMR, or justify their exclusion.

Dominion Response:

In Dominion's letter Serial No. 04-327, dated July 7, 2004, Dominion indicated that the containment air monitoring components downstream of 2-AC-527 and 2-AC-529 on license renewal drawing 25203-LR26028, Sh. 2, were inadvertently omitted from scope. These components support the radiation monitor actuation function to secure containment purge flow in the event of a fuel handling accident within the containment and, therefore, are in the scope of license renewal. The Process and Area Radiation Monitoring System screening results and AMR results have been updated to include the additional component types and there are no aging effects requiring management.

Supplemental Information:

In a November 1, 2004 telephone conversation, the staff requested that the updated LRA table with the information related to the added components in response to RAI 2.3.3.28-1A be provided.

The necessary additions to the LRA table are included in Dominion letter Serial No. 04-327, dated July 7, 2004, as indicated in the response to RAI 2.3.3.28-1A (provided in Dominion letter Serial No. 04-405, dated July 26, 2004). The added component types Fan/Blower Housings, Filter Housings, and Radiation Detectors are included in the table in Dominion letter Serial No. 04-327, including the associated intended functions for these components. The piping, tubing, and valves added to scope in response to RAI 2.3.3.28-1A are included in the existing component types Piping, Tubing, and Valves, respectively, in LRA Table 2.3.3-27 and there are no changes to the LRA information as a result of these additional components.

RAI 2.4-5

Section 2.4.1, Containment In both the Millstone 2 and Millstone 3 LRAs, Section 2.4.1 "Containment" describes containment electrical penetrations as follows: The electrical penetrations consist of an electrical penetration module installed into a penetration sleeve that is welded to the liner plate. The evaluation boundary consists of the sleeve and attachment weld to the electrical penetration module. Spare electrical penetrations are also part of the evaluation boundary. The electrical penetration module is evaluated as described in Section 2.5.2, Electrical Penetrations. LRA Section 2.5.2 "Electrical Penetrations" states: Electrical penetrations permit the conduction of electrical power or signals through the Containment wall while maintaining the integrity of the Containment pressure boundary. The electrical penetration feed-through modules consist of one or more electrical conductors in a tubular metallic cylinder. The cylinder passes through a header plate which is manufactured with an adapter ring that is field-welded to the Containment penetration sleeve to provide the Containment pressure boundary. The header plate may contain one or more modules that make up the total electrical penetration assembly. The modules contain conductor extensions, conductor supports, and seals which are either epoxy, O-ring, or mechanical compression seals. Nitrogen is used for monitoring of seal pressure integrity. From the information provided in the LRAs, it appears that the AMR for the Containment pressure boundary function of the electrical penetration feed-through modules is evaluated as part of the electrical scope, instead of as part of the structures scope. The staff considers the Containment pressure boundary function of the electrical penetration feed-through modules to be part of the structures scope. The applicant is requested to submit an AMR for the Containment pressure boundary function of electrical penetration feed-through modules as part of the structures scope.

Dominion Response:

The evaluation boundaries for the containment electrical penetrations are described in LRA Sections 2.4.1 and 2.5.2 and the aging management review results are provided in LRA Tables 3.5.2-1 and 3.6.2-2. The information provided in these sections meets the requirements of 10 CFR 54.21(a). Therefore, no changes to the LRA are deemed necessary.

Supplemental Information:

In a November 9, 2004 telephone conversation, the staff requested further clarification of the containment pressure boundary function and the aging management review results for the electrical penetration feed-through modules. In addition, the staff requested that Dominion provide the basis that there is no aging management program for the portion of the electrical penetration modules that provide the containment pressure boundary function, or provide an aging management program for these components.

As described in LRA Section 2.5.2, the electrical penetration feed-through module is installed in a Containment structure penetration by field welding the module header plate to the Containment liner via an adapter ring. The sleeve and weld are further described in LRA Section 2.4.1. The electrical penetration module, header plate, adapter, and sleeve, and the associated field weld, provide a Containment pressure boundary function. The module, including non-metallic penetration seals, compression connectors, and feed-through sealants, and the header plate are evaluated for the effects of aging based on the Containment pressure boundary function as indicated in LRA Table 3.6.2-2. The Containment penetration sleeve, adapter, and associated welds are evaluated for the effects of aging based on the Containment pressure boundary function as Electrical Penetrations and the results are provided in LRA Table 3.5.2-1.

As indicated in LRA Table 3.5.2-1, the electrical penetrations were determined to be subject to loss of material and are managed for the effects of aging by the Inservice Inspection Program: Containment Inspections AMP. This AMP is described in LRA Section B2.1.16 and is modified by the response to RAI 3.5-1 provided in Dominion letter SN 04-673 dated 11/9/04.

After further consideration, and in response to NRC staff concerns, the aging management review results provided in LRA Table 3.6.2-2 for the Feed-through Sealant and the Penetration Seals component types are supplemented to indicate that the aging effects of cracking and change of material properties will be managed by the Inspection Program: Containment Inspections AMP as modified by the response to RAI 3.5-1 provided in Dominion letter SN 04-673 dated 11/9/04.

Attachment 3

Additional Information in Support of Applications for Renewed Operating Licenses

Millstone Power Station Units 2 & 3
Dominion Nuclear Connecticut, Inc.

The following additional information, in support of the Millstone Power Station, Units 2 and 3 License Renewal Applications (LRAs), is provided as a result of audits of the Aging Management Programs (AMP) and Aging Management Reviews (AMR),

Audit Item 191

In MPS LRA, Appendix B, Section B2.1.9, the applicant states that AMP B2.1.9 is consistent with the program as modified in staff's draft ISG-15. ISG-15 requires that "review of calibration results or findings of surveillance program can provide and indication of the existence of aging effects based on acceptance criteria related to instrumentation circuit performance. By reviewing the results obtained during normal calibration or surveillance, an applicant may detect severe aging degradation prior to the loss of the cable and connection intended function. The first review will be completed before the end of the initial 40-year license term and at least 10 years thereafter. All calibration or surveillance results that fail to meet acceptance criteria will be reviewed for aging effects when the results are available." MPS AMP B2.1.9, under Enhancements heading, does not require a review of calibration or surveillance results for indication of cable degradation. Revise AMP B2.1.9 to include this requirement or provide justification of why the review is not necessary.

Dominion Response:

To clarify the monitoring of aging for instrumentation cables that are tested in situ, the following commitment will be added to LRA Appendix A, "FSAR Supplement" Section A2.1.9 for Unit 2 and Section A2.1.8 for Unit 3.

"• Review of Surveillance Test Results for Cables Tested In Situ

"Calibration results for cables tested in situ will be reviewed to detect severe aging degradation of the cable insulation. The initial review will be completed prior to the period of extended operation and will include at least 5 years of surveillance test data for each cable reviewed. Subsequent reviews will be performed on a period not to exceed 10 years.

"This commitment is identified in Appendix A, Table A6.0 -1 License Renewal Commitments, Item [32 for Unit 2] [Item 33 for Unit 3]."

An additional item will be added to Unit 2 and Unit 3 Appendix A "FSAR Supplement", Table A6.0 -1 as follows:

Item: "32" (Unit 2) and "33" (Unit 3)

Commitment: "Calibration results for cables tested in situ will be reviewed to detect severe aging degradation of the cable insulation. The initial review will be completed prior to entering the period of extended operation and will include at least 5 years of surveillance test data for each cable reviewed. Subsequent reviews will be performed on a period not to exceed 10 years."

Source: "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"

Schedule: "Prior to Period of Extended Operation
Not to Exceed a 10 Year Frequency Thereafter."

Audit Item 192

Inaccessible medium-voltage cables may be exposed to condensation and wetting in inaccessible locations, such as conduits, cable trenches, cable troughs, and duct banks. When an energized medium-voltage cable is exposed to wet conditions for which it is not designed, water treeing or a decrease in the dielectric strength of the conductor insulation can occur. This can potentially lead to electrical failure. The growth and propagation of water trees is somewhat unpredictable.

In MPS AMP B2.1.14, the applicant states that this program uses periodic action, such as pumping and inspection of cables vaults, to prevent cables from being submerged. In the event that submerged cables are found, an engineering evaluation will be perform and the appropriate testing required will be specified, as necessary to confirm the condition of the cable insulation. GALL XI.E3 states that in-scope, inaccessible medium-voltage cables exposed to significant moisture (periodic exposure to moisture that last more than few days (emphasize added)) and significant voltage are tested at least once every 10 years to provide an indication of the cable insulation condition.

a. How often are inspections performed?

b. Provide technical justification of how visual inspections are adequate to prevent cables from being subject to significant moisture (last more than few days).

Dominion Response:

As part of the AMR process, Millstone identified two Unit 3 duct lines with low points that are susceptible to moisture accumulation. These two duct lines contain 26 in-scope medium voltage cables. No similar duct lines were identified on Unit 2. Prior to the period of extended operation, these cables will be tested to demonstrate that water treeing will not prevent the cables from performing their intended function.

The other duct banks on both units are not susceptible to moisture accumulation due to the slope of the embedded conduit between manholes and the inspections required by the Structures Monitoring AMP. The duct banks consist of 5-inch Schedule 40 PVC pipe embedded in reinforced concrete, which is founded on dense soil over bedrock. The applied contact pressure by the duct banks is well below the allowed bearing pressure of the supporting material resulting in insignificant settlement (Ref. Unit 2 FSAR Section 2.7.5.2). Therefore, the duct banks will maintain the design cable run slope to their respective termination points in manholes or buildings and the Structures Monitoring AMP inspections will identify any water intrusion.

For the cable in these duct banks, the design, in conjunction with the Structures Monitoring AMP inspections, ensures that any cable that becomes submerged will be identified by the AMP inspections. The Inaccessible Medium Voltage Cables Not

Subject to 10 CFR 50.49 Environmental Qualification Requirements AMP currently addresses the testing of cables that have been submerged. For the cables that have not been submerged, the aging effect of water treeing is precluded and testing is not required.

To implement the testing of inaccessible medium voltage cables identified in the two Unit 3 duct lines with low points that are susceptible to moisture accumulation, the following commitment will be added to LRA Appendix A, "FSAR Supplement" Unit 2 Section A2.1.14 and Unit 3 Section A2.1.13:

"• Testing of Inaccessible Medium Voltage Cables

"The Unit 3 duct lines # 929 (SBO Diesel to Unit 3 4.16kV Normal Switchgear) and # 973 (RSST 3RTX-XSR-B to 6.9kV Normal Switchgear Bus 35A, 35B, 35C and 35D) have low points that are susceptible to moisture accumulation. Prior to the period of extended operation, the in scope cables in these two duct lines will be tested to demonstrate that water treeing will not prevent the cables from performing their intended function. Subsequent testing will be performed on a frequency not to exceed a 10-year interval.

"This commitment is identified in Appendix A, Table A6.0 -1 License Renewal Commitments as Item [33 for Unit 2] [34 for Unit 3]."

An additional item will be added to Unit 2 and Unit 3 Appendix A "FSAR Supplement", Table A6.0 -1 as follows:

Item: "33" (Unit 2) and "34" (Unit 3)

Commitment: "The in scope cables in Unit 3 duct lines # 929 (SBO Diesel to Unit 3 4.16kV Normal Switchgear) and # 973 (RSST 3RTX-XSR-B to 6.9kV Normal Switchgear Bus 35A, 35B, 35C and 35D) will be tested to demonstrate that water treeing will not prevent the cables from performing their intended function. "

Source: "Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"

Schedule: "Prior to Period of Extended Operation
Not to Exceed a 10 Year Frequency Thereafter."