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10 CFR 50
10 CFR 51
10 CFR 54

RS-13-247

November 5, 2013

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

Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
NRC Docket Nos. STN 50-456 and STN 50-457

Byron Station, Units 1 and 2
Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

Subject: Response to NRC Requests for Additional Information, Set 1, dated October 7, 2013, related to the Braidwood Station, Units 1 and 2 and Byron Station, Units 1 and 2 License Renewal Application

References:

1. Letter from Michael P. Gallagher, Exelon Generation Company LLC (Exelon) to NRC Document Control Desk, dated May 29, 2013, "Application for Renewed Operating Licenses."

2. Letter from John W. Daily (NRC) to Michael P. Gallagher (Exelon), dated October 7, 2013, "Requests for Additional Information for the Review of the Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2, License Renewal Application – Aging Management, Set 1 (TAC NOS. MF1879, MF1880, MF1881, AND MF1882)

In the Reference 1 letter, Exelon Generation Company, LLC (Exelon) submitted the License Renewal Application (LRA) for the Braidwood Station, Units 1 and 2, and Byron Station, Units 1 and 2 (BBS). In the Reference 2 letter, the NRC requested additional information to support the staffs' review of the LRA.

Enclosure A contains the responses to these requests for additional information.

Enclosure B contains updates to sections of the LRA (except for the License Renewal Commitment List) affected by the responses.

Enclosure C provides an update to the License Renewal Commitment List (LRA Appendix A, Section A.5). There are no other new or revised regulatory commitments contained in this letter.

If you have any questions, please contact Mr. Al Fulvio, Manager, Exelon License Renewal, at 610-765-5936.

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

Executed on 11-5-2013

Respectfully,

Michael P. Gallagher
Vice President - License Renewal Projects
Exelon Generation Company, LLC

Enclosures: A: Response to Requests for Additional Information
B: Updates to affected LRA sections
C: License Renewal Commitment List Changes

cc: Regional Administrator – NRC Region III
NRC Project Manager (Safety Review), NRR-DLR
NRC Project Manager (Environmental Review), NRR-DLR
NRC Senior Resident Inspector, Braidwood Station
NRC Senior Resident Inspector, Byron Station
NRC Project Manager, NRR-DORL-Braidwood and Byron Stations
Illinois Emergency Management Agency - Division of Nuclear Safety

Enclosure A

Byron and Braidwood Stations (BBS), Units 1 and 2
License Renewal Application
Response to Requests for Additional Information

RAI 2.1.5.2-1
RAI 2.1.5.2-2
RAI B.2.1.3-1
RAI B.2.1.3-2
RAI B.2.1.3-3

RAI 2.1.5.2-1, 1CB006 and similar SSCs

Applicability:
Bryon Nuclear Station (Byron) and Braidwood Nuclear Station (Braidwood), all units

Background:
License renewal application (LRA) Section 2.1.5.2, "Nonsafety-Related Affecting Safety Related–10 CFR 54.4(a)(2)" (pg. 2.1-24), states, in part:

> However, there is the potential for communications between nonsafety-related [Systems, Structures, and Components] SSCs located in the turbine building and safety-related SSCs located in the adjacent Auxiliary Building due to ventilation openings in the wall that separates these two structures. Therefore, water, oil, or steam filled SSCs located within the vicinity of these ventilation openings are included within the scope of license renewal due to potential for spatial separation.

During the on-site scoping and screening methodology audit, the staff performed a walkdown of the emergency diesel generators (EDGs), portions of the main steam and feedwater lines, and the gland steam condenser lines located near the EDG ventilation openings and between the auxiliary and turbine buildings. During the walkdown, the staff identified components and later performed a review to determine if these components were included within the scope of license renewal in accordance with LRA Section 2.1.5.2.

Issue:
As a result of this review, the staff identified that valve 1CB006 and the associated condensate piping were not included in the scope for license renewal. Additionally, the licensee did not identify this valve in any of the license renewal drawings.

Request:
Please provide a justification for not including valve 1CB006 and associated piping within the scope of license renewal in accordance with the requirements of LRA Section 2.1.5.2. The staff also requests that the applicant perform an extent of condition review and indicate whether the review identifies additional components that were not included in the scope of license renewal. Provide a list of these components, if applicable.

Exelon Response:

During the scoping and screening methodology audit performed at Byron Station, it was identified that the Unit 1 Condenser Spray Isolation Valve (1CB006) and the downstream piping (1CB44A) that are in the vicinity of the HVAC openings to the emergency diesel generator rooms were not in scope per the license renewal boundary drawing. In reviewing this issue, it was determined that the components should have been shown on the license renewal boundary drawings, highlighted in red, to indicate that the components are within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). 1CB006, which is shown on an interfacing station piping and instrumentation drawing, is added to the license renewal boundary drawing LR-BYR-M-39, Sheet 2 at coordinate F-7. The valve, along with the required section of 1CB44A up to the point where the line goes through the 401' elevation floor, is in scope for license renewal. This change does not result in any revision to the LRA.

During the scoping phase of the LRA, physical arrangement drawings were marked up to identify portions of systems that meet scoping criterion 10 CFR 54.4(a)(2). It has been determined that the discrepancy described above was due to an error in the transfer of the scoping determinations from the physical arrangement drawings to the license renewal boundary drawings. To assess potential extent of condition concerns, all of the license renewal boundary drawings that identify portions of systems within the scope of license renewal due to turbine building spatial interaction concerns were reviewed against the original source documents. Additionally, field walkdowns were conducted to provide additional assurance that there were no other components that should have been included in scope that were not identified on a license renewal boundary drawing.

The extent of condition review identified that minor revisions to the license renewal boundary drawings, listed in the second column of the following table, are required to show the correct license renewal scoping of the components listed in the third column of the table. Impacts to the LRA are identified in the far right column of the table. Minor revisions to LRA Section 3.3.2.16 and Table 3.3.2-16 are required to add the Air-Indoor (External) environment to the Heating Water & Heating Steam System components located in the turbine building. These LRA changes are provided in Enclosure B of this submittal.

Extent of Condition Review Results

Unit	License Renewal Boundary Drawing	Component(s) Added to Scope of License Renewal	Description of the Revision to the License Renewal Boundary Drawing	LRA Impact
Braidwood 1	LR-BRW-M-39 Sheet 2 (F-7)	1CB006 Condenser Spray Isolation Valve and associated piping 1CB44A	The (a)(2) leakage boundary on the condensate spray header 1CBA7AA is extended upstream to line 1CB44A, including the manual block valve 1CB006, to the point where the line pass through 401' floor elevation.	None
Byron 2	LR-BYR-M-124 Sheet 2 (F-7)	2CB006 Condenser Spray Isolation Valve and associated piping 2CB44A	The (a)(2) leakage boundary on the condensate spray header 2CBA7AA is extended upstream to line 2CB44A, including the manual block valve 2CB006, to the point where the line pass through 401' floor elevation.	None
Braidwood 2	LR-BRW-M-124 Sheet 2 (F-7)	2CB006 Condenser Spray Isolation Valve and associated piping 2CB44A	The (a)(2) leakage boundary on the condensate spray header 2CBA7AA is extended upstream to line 2CB44A, including the manual block valve 2CB006, to the point where the line pass through 401' floor elevation.	None
Byron 1	LR-BYR-M-39 Sheet 3 (B-2)	1CD34AB piping section	The (a)(2) leakage boundary is extended between the SJAE and gland steam condenser outlet valve 1CD043B and condensate booster suction header 1CD34B.	None
Braidwood 1	LR-BRW-M-39 Sheet 3 (B-2)	1CD34AB piping section	The (a)(2) leakage boundary is extended between the SJAE and gland steam condenser outlet valve 1CD043B and condensate booster suction header 1CD34B.	None
Byron 1	LR-BYR-M-72 Sheet 2 (F-2)	1SH15AR unit heater and associated piping 1SH05AT and 1SH04DT	The (a)(2) leakage boundary is extended to include the unit heater and the supply and discharge piping.	Section 3.3.2.16 and Table 3.3.2-16 (see Enclosure B)
Braidwood 1	LR-BRW-M-72 Sheet 2 (F-2)	1SH05AT piping section (unit heater is removed)	The (a)(2) leakage boundary is extended to include the previously capped unit heater discharge piping.	Section 3.3.2.16 and Table 3.3.2-16 (see Enclosure B)
Byron 1	LR-BYR-M-43 Sheet 2A (F-5)	Valves 1WS493 and 1WS494 and associated piping 1WS95A	The (a)(2) leakage boundary is extended to include non-essential service water hose connection.	None
Byron 2	LR-BYR-M-127 Sheet 2 (F-6)	Valves 0WS339 and 0WS498 and associated piping 2WS95A	The (a)(2) leakage boundary is extended to include non-essential service water hose connection.	None

RAI 2.1.5.2-2, Unidentified safety-related SSCs in Turbine Building

Applicability:
Byron and Braidwood Stations, all units

Background:
LRA Section 2.1.5.2, "Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)" (pg. 2.1-24), states in part:

> The [Byron Station and Braidwood Station] BBS turbine building contains a limited number of SSCs that are classified as safety-related. The components located in the turbine building that perform a safety-related function are either fail-safe or anticipatory and, therefore, are not targets for potential spatial interaction.

Issue:
The staff needs further information regarding the components referenced above.

Request:
Please provide the following information related to the safety-related SSCs located in the Byron and Braidwood turbine buildings:

1. Name of the SSC
2. Function of the SSC
3. Basis for concluding the SSC is either fail-safe or anticipatory
4. General location of the SSC

Exelon Response:

This RAI includes four (4) parts. For clarity, the RAI response is organized by SSC in sections A through F, below, corresponding to the six (6) components/component sets in question. The response to each part of the RAI (1-4) for the subject SSC is included in the appropriate section. The names of the SSCs in question (response to part 1 of this RAI) are provided in the title of sections A through F. Each of the safety-related SSCs described in the discussions below are included within the scope of license renewal in accordance with 10 CFR 54.4(a)(1).

A. Combustion Air Intake for the Diesel-Driven Auxiliary Feedwater Pump (DDAFP)

2. The combustion air intake for the DDAFP is a 14-inch air vent that is designed to allow combustion air to be drawn from the turbine building. The primary safety-related function of this component is to direct the flow of air from the turbine building to the DDAFP air intake. A secondary function is to act as a flood barrier to prevent flooding in the turbine building from impacting safety-related SSCs in the auxiliary building. This secondary function is accomplished by the vent acting as an extension of the common wall between the auxiliary building and the turbine building (known as the L-wall) from where the vent enters the turbine building (approximately elevation 392') up to above the highest postulated flood level in the turbine building (i.e., above the floor at elevation 401'). The portion of the combustion air intake for the DDAFP located in the turbine building does not have a pressure boundary intended function since it is an open ended atmospheric vent. Based on the above discussion, the portion of the combustion air

intake for the DDAFP that is located in the turbine building has a “Direct Flow” intended function and a “Flood Barrier” intended function.

3. Since the portion of the combustion air intake located in the turbine building does not have a pressure boundary intended function, it is not vulnerable to loss of safety function due to spatial interaction (leakage or spray). That is, accelerated long-term aging due to the affects of leakage of nonsafety-related equipment in the turbine building will not prevent the accomplishment of the safety-related function of the DDAFP. In the unlikely event that a nonsafety-related component in the vicinity of the combustion air intake air vent fails and the leakage from this component causes accelerated aging of the DDAFP intake air vent the only plausible aging would be loss of material. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program, the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting (B.2.1.25) aging management program, and the Structures Monitoring (B.2.1.34) aging management program are credited with managing the aging (i.e., loss of material) of the combustion air intake for the DDAFP. In the unlikely event that the loss of material of the DDAFP combustion air intake line goes unnoticed and is allowed to progress despite aging management of the vent, a through-wall hole will develop. As this is a suction line whose primary function is to direct the flow of combustion air to the diesel engine air intake, a through-wall hole will not prevent DDAFP from performing its safety-related function. Since the failure of the combustion air intake line (through interaction with a failed nonsafety-related SSC) will not prevent the accomplishment of the safety-related intended function, this component is considered fail-safe in accordance with the guidance presented in Section 5.2.3.1 of Appendix F of NEI 95-10. With respect to the flood barrier function of the combustion air intake line, degradation of the function would occur in the unlikely event that a through-wall leak was to develop. However, components with a flood barrier function (e.g., flood barrier walls, doors, and seals) are designed to maintain their function in the environment that could be caused by the failure of a nearby nonsafety-related SSC and, therefore, in accordance with the guidance presented in Section 5.2.3.2 of Appendix F of NEI 95-10, these components are not considered vulnerable to spatial interaction with surrounding nonsafety-related SSCs.

4. The DDAFP for each unit is located in the auxiliary building at floor elevation 383’ along the L-wall approximately 25 feet from the common wall between Unit 1 and Unit 2. The combustion air intake line begins at the DDAFP and penetrates the L-wall at elevation 392’ and is routed approximately five (5) feet perpendicular to the L-wall and then upward to the 401’ elevation. The combustion air intake air vent terminates above the elevation 401’ floor at a gooseneck that is capped with a nonsafety-related expanded metal screen that prevents debris from entering the combustion air intake for the diesel.

B. Diesel Oil Storage Room Vents

2. The diesel oil storage room vents are a series of 14-inch air vent lines that provide a suction path from and a return path to the turbine building for the diesel oil storage room ventilation system. The primary safety-related function of this component is to provide a flowpath to allow air to be drawn from and returned to the turbine building. A secondary function is to act as a flood barrier to prevent flooding in the turbine building from impacting safety-related SSCs in the auxiliary building. This secondary function is accomplished by the vent acting as an extension of the L-wall from where the vents

enter the turbine building (approximately elevation 395') up to above the highest postulated flood level in the turbine building (i.e., above the floor at elevation 401'). The portions of the diesel oil storage room vents located in the turbine building do not have a pressure boundary intended function since they are open ended atmospheric vents. Based on the above discussion, the portions of the diesel oil storage room vents located in the turbine building have a "Direct Flow" intended function and a "Flood Barrier" intended function.

3. Since the portions of the diesel oil storage room vents located in the turbine building do not have a pressure boundary intended function, they are not vulnerable to loss of safety function due to spatial interaction (leakage or spray). That is, accelerated long-term aging due to the affects of leakage of nonsafety-related equipment in the turbine building will not prevent the accomplishment of the safety-related function of the diesel oil storage room ventilation system. In the unlikely event that a nonsafety-related component in the vicinity of the diesel oil storage room vents fails and the leakage from this component causes accelerated aging of the diesel oil storage room vents the only plausible aging would be loss of material. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program, the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting (B.2.1.25) aging management program, and the Structures Monitoring (B.2.1.34) aging management program are credited with managing the aging (i.e., loss of material) of the diesel oil storage room vents. In the unlikely event that the loss of material of the diesel oil storage room vents goes unnoticed and is allowed to progress despite aging management of the vents, a through-wall hole will develop. As these are atmospheric vents whose primary function is to direct the flow of air to and from the turbine building, a through-wall hole in the portion of the vent line in the turbine building will not prevent diesel oil storage room ventilation system from performing its safety-related function. Since the failure of the atmospheric vents (through interaction with a failed nonsafety-related SSC) will not prevent the accomplishment of the safety-related intended function, these components are considered fail-safe in accordance with the guidance presented in Section 5.2.3.1 of Appendix F of NEI 95-10. With respect to the flood barrier function of the atmospheric vents, degradation of the function would occur if a through-wall leak were to develop. However, components with a flood barrier function (e.g., flood barrier walls, doors, and seals) are designed to maintain their function in the environment that could be caused by the failure of a nearby nonsafety-related SSC and, therefore, in accordance with the guidance presented in Section 5.2.3.2 of Appendix F of NEI 95-10, these components are not considered vulnerable to spatial interaction with surrounding nonsafety-related SSCs.

4. There are two (2) diesel oil storage rooms for each unit. The diesel oil storage rooms for each unit are located in the auxiliary building at floor elevation 383' along the L-wall at the opposite end of the turbine building from the common wall between Unit 1 and Unit 2. The diesel oil storage room vent plenums penetrate the L-wall at elevation 395'. The vent lines attached to the plenums are routed upward to the 401' elevation. The diesel oil storage room vents terminate above the elevation 401' floor at a gooseneck that is capped with a nonsafety-related expanded metal screen that prevents debris from entering the combustion air intake for the diesel. The goosenecks are located in the area in front of the diesel generator rooms on elevation 401'.

C. Essential Service Water Sample Valves at Byron Only

(Note: The essential service water sample valves at Byron are not anticipatory or fail-safe. However, these valves are located in valve enclosures embedded in the base mat of the turbine building. The valve enclosures are covered and, therefore, are considered a different "space" for purposes of 10 CFR 54.4(a)(2) scoping for spatial interaction. Regardless, a discussion of these valves is included in this response for completeness.)

2. This issue is applicable only to Byron due to the differences between the essential service water systems at Byron and Braidwood. At Byron only, there are four (4) safety-related ¾-inch sample valves (one on each suction header and one on each return header for the two essential service water system loops), and associated piping, that allow the essential service water system to be monitored for pH and corrosion products. These valves serve as the isolable component that acts as the boundary between the safety-related essential service water system and the nonsafety-related process sampling system. Therefore, these valves are relied upon to maintain the pressure boundary of the safety-related essential service water system and are assigned a "Pressure Boundary" intended function for license renewal aging management review.

3. The four (4) essential service water sample valves, and associated piping, at Byron are located in a recessed valve enclosure in the base mat of the turbine building. The valve enclosure is covered and, as such, the enclosed valve is protected from spatial interaction due to failure of nonsafety-related water-, steam-, or oil-filled components in the turbine building. The cover of the valve enclosure is included within the scope of license renewal since it performs a shelter and protection intended function. The cover is evaluated with the turbine building for aging management review. Aging of the cover is managed by the Structures Monitoring (B.2.1.34) aging management program. Therefore, despite the fact that the valves are located within the footprint of the turbine building, the valves are considered to be in a separate "space". The portion of the process sampling line that is located within the valve enclosure is included in scope for potential spatial interaction with the essential service water sample valves in accordance with the requirements of 10 CFR 54.4(a)(2).

4. The four (4) essential service water sample valves at Byron are located in four (4) recessed valve enclosures in the base mat of the turbine building. The valve enclosures are embedded in the turbine building floor at elevation 401' on the far side of the building from the L-wall near the common wall between Unit 1 and Unit 2.

D. Feedwater Valve Isolation Instrumentation

2. In specific accident analyses, credit is taken for the isolation of feedwater flow to the steam generators. Two isolation valves in series are provided to prevent flow out of containment (one check valve and one hydraulically operated valve). However, the check valve will not prevent flow into the containment from the feedwater system. Therefore, if an active failure of a main feedwater isolation valve is postulated, credit is taken for the closure of the feedwater regulating valves, feedwater bypass regulating valves, and tempering flow control valves located in the turbine building for isolation of the feedwater system. An RPS signal is sent to trip the feedwater pumps and close its discharge valves as well as close all the feedwater valves identified above. The feedwater regulating valves, feedwater bypass regulating valves, and tempering flow

control valves are nonsafety-related components that functionally support a 10 CFR 54.4(a)(1) function and, therefore, are in scope in accordance with 10 CFR 54.4(a)(2). These components are assigned a “Pressure Boundary” intended function for license renewal aging management review.

3. The feedwater regulating valves, feedwater bypass regulating valves, and tempering flow control valves fail close on loss of air or loss of power. Therefore, the feedwater isolation feature is fail-safe. There is no credible failure of the isolation instrumentation, including a failure induced by spatial interaction with surrounding nonsafety-related water-, steam-, or oil-filled components, that would prevent the isolation of the feedwater system from occurring. Therefore, the feedwater isolation instrumentation is not vulnerable to spatial interaction with surrounding nonsafety-related SSCs. The feedwater regulating valves, the feedwater bypass regulating valves, and the tempering flow control valves are nonsafety-related components that provide functional support of an 10 CFR 54.4(a)(1) function and, as such, are in scope in accordance with 10 CFR 54.4(a)(2). Therefore, these valves are not targets for spatial interaction.

4. The feedwater regulating valves, feedwater bypass regulating valves, and tempering flow control valves, and associated instrumentation, are located on elevation 401’ of the turbine building near the door for the “A” diesel generator room.

E. Reactor Trip System Instrumentation

2. The reactor trip system instrumentation includes (1) a series of pressure switches that monitor oil pressure in the electro-hydraulic control (EHC) emergency trip header, (2) a series of position switches that monitor the valve stem position for the main high pressure turbine stop valves, and (3) a series of pressure transmitters that monitor turbine impulse chamber pressure. When above 30% power, this instrumentation provides a trip signal to the reactor protection system (RPS) upon a turbine trip.

3. As described in UFSAR Section 7.2.1.1.2.f, instrumentation to allow for a reactor trip on a turbine trip is an anticipatory design feature that provides additional protection and conservatism. No credit is taken in any of the UFSAR Chapter 15 safety analyses for this trip. The reactor trip instrumentation is not required to perform a 10 CFR 54.4(a)(1) function since the reactor trip instrumentation performs an anticipatory function that is not credited in any UFSAR Chapter 15 safety analysis and, therefore, the failure of this instrumentation will not prevent a 10 CFR 54.4(a)(1) function. There is no credible failure of the reactor trip instrumentation, including a failure induced by spatial interaction with surrounding nonsafety-related water-, steam-, or oil-filled components, that would prevent a reactor trip from occurring. Therefore, the reactor trip instrumentation is not a target for spatial interaction.

4. The EHC pressure switches, high pressure turbine stop valve position switches, and turbine impulse chamber pressure transmitters (i.e., the reactor trip system instrumentation) are located on elevation 451’ of the turbine building near the high pressure turbine.

F. Auxiliary Steam System Isolation Instrumentation

2. High energy line break (HELB) reviews identified auxiliary steam supply lines supporting equipment within the auxiliary building. The auxiliary steam system has isolation logic in place to secure the steam supply within the turbine building, using air-operated valves that are installed in series, prior to the lines entering the auxiliary building. While not safety-related, power for the isolation instrumentation is provided from safety-related power sources in the auxiliary building.

3. The auxiliary steam system isolation instrumentation is designed with a fail-safe design feature, where a loss of power or air causes an isolation to occur. The power supply has adequate breaker isolation to prevent faults from propagating back into the safety-related sources. There is no credible failure of the auxiliary steam system isolation instrumentation, including a failure induced by spatial interaction with surrounding nonsafety-related water-, steam-, or oil-filled components, that would prevent the performance of a safety-related function and, as such, the isolation instrumentation is not vulnerable to spatial interaction. Therefore, the auxiliary steam system isolation instrumentation is not a target for spatial interaction.

4. The auxiliary steam system isolation valves, and associated instrumentation, are located on elevation 451' of the turbine building near the Unit 2 low pressure feedwater heaters.

RAI B.2.1.3-1, Byron Closure stud OE not included in LRA

Applicability:
Byron, Units 1 and 2

Background:
During the audit of the "operating experience" program element for Byron, Units 1 and 2, the staff found that operating experience provided by the applicant in the LRA was incomplete. Specifically, the applicant's onsite database contained information related to a stuck reactor vessel closure stud for Byron Unit 2. Based on the information provided by the applicant during the audit, Stud No. 11 became stuck in the 2010 outage and did not have enough thread engagement to be tensioned. The applicant decided to leave the stuck stud in place after cutting approximately 5 inches from the top end of the stuck stud. Since 2010, Byron, Unit 2, has only 53 of 54 studs operable.

Issue;
The LRA does not provide any information regarding the significant plant-specific operating experience relative to Stud No. 11 for Byron, Unit 2. In addition, no information was provided in the LRA or during the audit on the root cause of the failure. Without a root cause, the staff is concerned that similar failures could reoccur and further challenge the integrity of the reactor vessel head.

Request:
1. Perform a complete plant-specific search of reactor vessel closure studs operating experience for Byron, Units 1 and 2. In addition to Stud No. 11, provide search results that include all instances of stuck studs, missing threads, damaged threads, or any form of degradation in reactor pressure vessel studs, washers, vessel flange threads, and nuts.
2. Provide a detailed chronology of the events related to Byron, Unit 2, Stud No. 11.
3. Provide a root cause analysis related to the failure of Stud No. 11. Include corrective actions, inspection results, engineering changes, repair replacement activities related to Stud No. 11 and its respective flange hole.
4. For Byron, Unit 2, explain in detail the current configuration of Stud No. 11 and the flange hole.

Exelon Response:

1. A thorough operating experience review has been performed to identify all documented instances of stuck studs, missing threads, damaged threads, or any form of degradation in reactor pressure vessel studs, washers, vessel flange threads, and nuts at Byron Units 1 and 2. This review did not identify any events at Byron Units 1 and 2 caused by age-related degradation including cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or loss of material due to wear or corrosion.

   The operating experience review involved key word searches of the Byron Station Passport Action Request (AR) database, Exelon's Electronic Document Management System (EDMS) regulatory correspondence database, and the NRC's LER databases.

In addition, Byron Unit 1 and 2 ISI Inspection Summary Reports and applicable inspection reports were reviewed.

Below are summaries of the applicable events and conditions (i.e., instances of stuck studs, missing threads, damaged threads, or any form of degradation in reactor pressure vessel studs, washers, vessel flange threads, and nuts at Byron Unit 1 and Unit 2) that were identified by the operating experience review.

- For Byron Unit 2, during the 2010 outage reactor head closure stud 11 became stuck as described below. Review of the event description indicated the stuck stud was not caused by aging effects such as cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or loss of material due to corrosion. With respect to the "wear" aging mechanisms, NUREG 1801, Revision 2 provides guidance: "wear occurs in components that experience intermittent relative motion, frequent manipulation, or in clamped joints where relative motion is not intended, but may occur due to a loss of the clamping force." Wear or galling caused by event driven physical damage (e.g., due to human error) is not age-related degradation. Based on this guidance the event was concluded not to be due to age-related loss of material due to wear. For additional details, refer to the response to request number 3, below.

- In October 2008, during Byron Unit 2 reactor head disassembly, a light ring of surface rust and boric acid residue was found on reactor head closure stud 51. Observation indicated that this ring was very light with only a small amount of white boric acid residue. No material loss of the stud was reported. The ring was found on the stud just above the bottom threads, which corresponds to the reactor vessel flange stud plug relief area. Inspection showed no signs of reactor coolant leakage, rust or boric acid residue on nearby studs or on the reactor vessel flange. The apparent cause was the accumulation of a small amount of borated water in the reactor vessel flange stud plug relief area during reactor assembly in the previous refueling outage. The borated water evaporated during heat up and left behind the light ring and boric acid residue. Stud 51 was cleaned prior to reinstallation during reactor assembly in the 2008 refueling outage.

- For Byron Unit 2, visual inspection reports documented light surface corrosion on washers 11, 17, and 18 during the spring 2004 refueling outage and light surface corrosion on nuts 19 and 20 during the spring 2007 refueling outage. No material loss of these nuts and washers was reported. In addition, for Byron Unit 2, a 1/16 inch by 0.05 inch deep small dent was observed on washer 16 during the spring 2004 refueling outage. These observations were properly not reported as a "recordable indications" in the corresponding ISI Inspection Summary Reports. The surface corrosion on the nuts and washers were cleaned prior to reactor assembly.

- In September 2002, during Byron Unit 2 reactor head assembly and after all studs had been tensioned, reactor head closure stud number 51 was found "bottomed out" in its associated reactor vessel flange stud hole. This is contrary to the procedure guidance that all studs should be backed out of the reactor

flange stud hole approximately one half a turn. During reactor head assembly, all studs are fully inserted into the vessel flange (bottomed out) and then rotated half a turn out of the flange prior to tensioning. The purpose of this practice is to reduce the potential for stuck studs.

Stud movement can occur during the tensioning process as the stud sometimes rotates slightly during the installation and turning of the nut. The "bottomed out" stud was evaluated by Exelon engineering and Westinghouse and concluded to be acceptable for operation since there was no impact on the structural integrity of reactor vessel closure during reactor operation. No difficulties were reported during the subsequent refueling outage when the stud 51 was removed.

- For Byron Unit 1, the spring 1999 and the spring 2008 ISI visual inspection reports documented, in the comment sections, a 15/32 inch by 1/8 inch "dent" on the outer diameter surface of the nut associated with reactor head closure stud 16. The size of the dent did not change from 1999 to 2008 and this nut is still in service. Because of its small size, this observation was properly not reported as a "recordable indication" in the corresponding ISI Inspection Summary Reports.

2. In 1999, eleven years before the Byron Unit 2 reactor head closure stud 11 became stuck, Byron Station developed contingency engineering analyses that concluded Byron Units 1 and 2 could operate with 53 of 54 reactor head closure studs tensioned while still meeting ASME Section III Code requirements. These contingency evaluations were developed in response to lessons learned from events related to stuck reactor head closure studs at other plants, including Braidwood Unit 2.

   In 2007, all Byron Unit 2 reactor head closure studs, including stud 11, were volumetrically examined in accordance with ASME Section XI, Table IWB-2500-1 resulting in no recordable indications.

   During the 2008 refueling outage, which is the refueling outage prior to Byron Unit 2 stud 11 becoming stuck, stud 11 was removed, inspected, lubricated, and reinstalled with no reported problems. A review of the completed 2008 refueling outage reactor disassembly and assembly work orders confirmed that all instructions related to stud 11 were followed with no reported problems. These instructions included procedural requirements for: stud detensioning; stud, nut, and washer removal and storage away from reactor cavity borated water; inspection and cleaning of the stud, nut, and washer; plugging and cleaning the associated vessel flange hole; reactor vessel and closure head flange and O-ring inspections; stud and flange hole lubrication; foreign material exclusion; and stud, nut, and washer installation and tensioning. At the conclusion of the 2008 refueling outage, the reactor vessel pressure test was performed in accordance with ASME Section XI, resulting in no observed leakage from the reactor vessel flange.

   In the spring of 2010, during reactor disassembly, Byron Unit 2 reactor head closure stud 11 initially became stuck two (2) turns out of the reactor vessel flange when the Biach electrical stud drive tool (ESDT) stopped rotating the stud. Additional attempts to rotate the stud with the Biach ESDT were unsuccessful. An approved lubricant was applied to the stud threads above the vessel flange hole with the intent that the lubricant would migrate down into the threads inside the vessel flange hole while the stud was manually

rotated in and out of the reactor vessel flange in quarter turn increments. Later, multiple unsuccessful attempts were made to manually free the stud by rotating it in and out of the flange. The stud's final as left position was four (4) inches out of the reactor vessel flange at which point the stud could no longer be manually rotated in or out of the reactor vessel flange. The top five (5) inches of the stud were then removed to provide the stud tensioning equipment with easier access to adjacent studs 10 and 12. Review of the completed reactor disassembly work order has confirmed that all instructions related to stud 11 were followed and signed off. The associated nut and washer for stud 11 have not been installed since the 2010 refueling outage.

An Engineering evaluation was then performed, authorizing a configuration in which stud 11 is not tensioned for power operation. UFSAR Section 5.3.1.7 and Table 5.3-2 were updated to reflect the new configuration, with the periodic UFSAR update submitted to the NRC in accordance with 10 CFR 50.71(e).

During the spring 2010, fall 2011, and spring 2013 Unit 2 refueling outages reactor vessel pressure tests, performed in accordance with ASME Section XI, resulted in no observed leakage from the reactor vessel flange. No reactor coolant leakage has been observed on the reactor flange since the stud became stuck. During the fall 2011 refueling outage all reactor flange stud holes, including the one associated with stud 11, were volumetrically examined in accordance with ASME Section XI, Table IWB-2500-1 resulting in no recordable indications. This inspection satisfies the ASME Section XI, Table IWB-2500-1 requirements for all reactor flanges stud holes in the third ISI Inspection ten-year interval.

3. Based on the review of Byron Unit 2 operating experience described above, reactor disassembly and assembly procedures, completed 2008 and 2010 reactor disassembly and assembly work orders, and personnel interviews, the most likely cause of the stuck stud 11 was undetected mechanical damage or galled threads during the handling process or the introduction of undetected foreign material in the reactor vessel flange hole. The review did not reveal any evidence that stud 11 became stuck due to age-related degradation.

   EPRI bolting good practices and guidelines indicate that the credible potential causal factors for the Byron Unit 2 stuck stud 11 are: (a) flange to bolt misalignment, (b) foreign material, (c) improper or no thread lubrication, (d) damaged or galled threads, (e) corrosion byproduct buildup on the stud and flange threads, and (f) stud to reactor vessel hole cross threading. Corrosion byproduct buildup, item e, is the only one of the above causal factors that is age-related. The following evaluation considers each of these casual factors in turn and explains why Byron Unit 2 stud 11 most likely became stuck due to undetected mechanical damage or galled threads during the handling process or the undetected introduction of foreign material in the reactor vessel flange hole and not due to age-related degradation.

   (a) Flange to bolt misalignment: The reactor assembly procedure provides specific guidance to prevent stud to reactor head flange to reactor vessel flange misalignment by tensioning the reactor head closure studs in a proceduralized pattern and sequence. In addition, the completed reactor reassembly work order from the 2008 refueling outage has been reviewed and no problems with the stud 11

installation were noted. It is not plausible that stud 11 could have been misaligned and installed without any problems. Based on the above, it is highly unlikely that Byron Unit 2 stud 11 became stuck due to misalignment of the stud to the reactor vessel flange.

(b) Foreign material: The reactor disassembly and assembly procedures provide specific guidance to minimize the likelihood of foreign material entering the reactor vessel flange hole or reactor head closure stud threads. This includes requiring that each stud and vessel flange hole are inspected and cleaned and that each vessel flange hole is plugged after removal of the stud and prior to flood up of the reactor cavity. In addition, after the reactor cavity is drained, borated water is removed from the stud plug relief areas and the areas are cleaned. The plugs are then removed and the vessel flange holes are again inspected. If any borated water has leaked past the plugs, the borated water is removed and the holes are cleaned. The completed reactor disassembly and assembly work orders were reviewed and indicate that these steps were completed during the 2008 refueling outage without issue for stud 11. Although these steps minimize the potential of foreign material intrusion into the stud and vessel flange threads, they may not eliminate the possibility of this occurrence. Should foreign material have been missed during the inspection and cleaning of stud 11 and the associated vessel flange hole, it is plausible that stud 11 could have been installed without any problems and become stuck only upon removal. Based on the above, it is plausible that Byron Unit 2 stud 11 became stuck due to the presence of foreign material.

(c) Improper or no thread lubrication: The disassembly and assembly procedures provide specific guidance to ensure proper lubrication of the reactor vessel flange hole and stud threads. The completed reactor disassembly and assembly work orders were reviewed and indicate that these steps were completed during the 2008 refueling outage without issue for stud 11. Based on the above, it is highly unlikely that Byron Unit 2 stud 11 became stuck due to improper or no thread lubrication.

(d) Damaged or galled threads: The reactor disassembly and assembly procedures provide specific guidance to minimize the likelihood of damaged or galled threads. This includes the use of the Biach electrical stud drive tool (ESDT) which is capable of supporting the weight of the stud during installation and removal and thereby minimizing the stress on the reactor vessel flange and stud threads. In addition, the procedures require that each reactor head closure stud, nut, and washer are match marked and are always installed and tensioned together in the same reactor vessel flange stud hole. Finally, the procedures require the inspection of the reactor head closure studs and reactor vessel flange stud holes to detect signs of physical damage. The completed reactor disassembly and assembly work orders were reviewed and indicate that these steps were completed during the 2008 refueling outage without issue for stud 11. Although these steps minimize the potential of damage to the stud and vessel flange threads, they may not eliminate the possibility of this occurrence. It is plausible that stud 11 could have been damaged without detection during the 2008 refueling outage or during removal in 2010 causing the stud to become stuck during removal in 2010. Based on the above, it is plausible that Byron Unit 2 stud 11 became stuck due to damaged or galled threads.

(e) Corrosion byproduct buildup on the stud and flange threads: The corrosion byproduct buildup causal factor is age-related and requires long term exposure to a corrosive environment to manifest into a stuck stud. The reactor disassembly and assembly procedures provide specific guidance to prevent corrosion by minimizing exposure of the reactor head closure studs and associated components to a corrosive environment. This includes plugging the reactor vessel flange stud holes and removing the studs, nuts, and washers from the reactor cavity and storing these components away from the borated water environment. In addition, the procedures require borated water to be removed from the stud plug relief areas and the stud holes to be inspected to ensure that no borated water migrated past the plugs while the reactor cavity is flooded. Finally, the reactor assembly procedure requires specific stud preload elongation to ensure the reactor vessel to reactor head flange is leak tight, thereby minimizing the potential for exposure of the reactor head stud area to reactor coolant during plant operation. The reactor disassembly and assembly procedures also provide specific guidance to detect corrosion of the reactor head closure studs and reactor vessel flange stud holes. This includes requiring the inspection and cleaning of each reactor head closure stud, nut, washer, and reactor vessel flange stud hole. The reactor vessel flange and “O-rings” are also inspected for grooves, steam cuts, oxidation, and boric acid crystals.

The above procedure instructions are intended to prevent long term corrosion byproduct buildup and are performed every outage and therefore, provide multiple opportunities to prevent a stuck stud that could theoretically be caused by corrosion byproduct buildup. It is not credible to conclude that there were multiple missed opportunities to detect and mitigate long term corrosion. The completed reactor disassembly and assembly work orders were reviewed and indicate that the steps described above were completed during the 2008 refueling outage without issue for stud 11. No sign of age-related degradation of Byron Unit 2 reactor head closure stud 11, or associated reactor vessel flange threads, was noted during reactor disassembly or assembly during the 2008 refueling outage. Based on the above, it is highly unlikely that Byron Unit 2 stud 11 became stuck due to corrosion byproduct buildup on the stud and flange threads.

(f) Stud to reactor vessel hole cross threading: The reactor disassembly and assembly procedures provide specific guidance to minimize the likelihood of stud to reactor vessel cross threading. This includes the use of the Biach (ESDT) which, as previously noted, minimizes the stress on the reactor vessel flange and stud threads. In addition, the completed reactor reassembly work order from the 2008 refueling outage has been reviewed and no problems with the stud 11 installation were noted. It is not plausible that stud 11 could have been cross threaded and installed without any problems. Based on the above, it is highly unlikely that Byron Unit 2 stud 11 became stuck due to stud to reactor vessel hole cross threading.

The corrosion byproduct buildup causal factor is age related and requires long term exposure to manifest into a stuck stud. As explained above, it is not credible to conclude that there were multiple missed opportunities to detect and mitigate long term corrosion. An operating experience review of industry PWRs which have also experienced stuck studs revealed no reported instances where the studs became stuck due to age-related loss of material degradation. Therefore, there is confidence that stud 11 did not become

stuck due to age-related degradation. Most likely, the stud became stuck due to undetected mechanical damaged or galled threads during the handling process or the introduction of undetected foreign material in the reactor vessel flange hole.

The reactor disassembly and assembly procedures at Byron are periodically revised to ensure that best practices are utilized to eliminate or mitigate the above casual factors. Procedure revisions incorporate lessons learned from site and industry events. For example, the Byron disassembly and assembly procedures have been revised 12 and 10 times respectively, since stud 11 became stuck in 2010. Some of these revisions include requirements to: perform additional prejob briefs, eliminate potential over head interference with the stud tension equipment, and inspect for foreign material that could be concealed under the reactor head prior to installing the reactor closure head. Given that Byron has removed, handled, stored, and reinstalled individual reactor head closure studs over 1800 times since commercial operation began, one (1) stuck stud, although not preferred, provides a positive indication that these procedures have significantly minimized the above causal factors. There is confidence that these procedures provide an effective process to eliminate or mitigate the above causal factors and that ongoing improvements implemented through the operating experience and corrective action programs will ensure that best practices are utilized to minimize the occurrence of stuck studs during the period of extended operation.

Reactor vessel pressure tests, in accordance with ASME Section XI, were performed during the spring 2010, fall 2011, and spring 2013 Unit 2 refueling outages, resulting in no observed leakage from the reactor vessel flange. During the fall 2011 refueling outage the area around all reactor flange stud holes, including the one associated with stud 11, were volumetrically examined in accordance with ASME Section XI, Table IWB-2500-1 resulting in no recordable indications.

A formal root cause evaluation of the 2010 refueling outage event has not been performed. A detailed visual inspection of the threads on the stud and associated reactor vessel flange hole would provide important information necessary to determine the root cause, but it is not possible to perform such a detailed inspection since the stud cannot be removed from the associated reactor vessel flange hole. Nevertheless, there is confidence that the root cause was not age-related degradation and steps have been taken to eliminate or mitigate the likely causal factors.

4. The current configuration of reactor head closure stud 11 and the reactor vessel flange hole are as follows. The stud is approximately four (4) inches out of the reactor vessel flange hole which has increased the distance between the bottom of the reactor vessel flange hole and the bottom of the stud by four (4) inches. The stud is stuck in this position and cannot be rotated either in or out of the reactor vessel flange. The top five (5) inches of the stud have been removed to provide the stud tensioning equipment with easier access to adjacent studs 10 and 12. This has resulted in the height of stud 11 to be less than 20 inches above the reactor head flange surface. An Engineering evaluation has been performed authorizing a configuration in which stud 11 is not tensioned for power operation. UFSAR Section 5.3.1.7 and Table 5.3-2 were updated to reflect the new configuration, with the periodic UFSAR update submitted to the NRC in accordance with 10 CFR 50.71(e). The associated nut and washer for stud 11 have been permanently removed since the 2010 refueling outage.

RAI B.2.1.3-2, BBS Closure Stud OE may not be bounded by GALL Report OE

Applicability:
Byron and Braidwood Stations, all units

Background:
LRA Section AMP B2.1.3 "Reactor Head Closure Stud Bolting" states that the aging management program (AMP) will be consistent with the ten elements of AMP XI.M3, "Reactor Head Closure Stud Bolting," specified in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," with an exception and an enhancement to the "preventive measures" program element.

The Abstract in Chapter XI of the GALL Report states, "if an applicant takes credit for a program in the GALL Report, it is incumbent on the applicant to ensure that the conditions and operating experience at the plant are bounded by the conditions and operating experience for which the GALL Report program was evaluated. If these bounding conditions are not met, it is incumbent on the applicant to address the additional effects of aging and augment the GALL Report aging management program(s) as appropriate." The staff performed a search of operating experience and noted that Byron, Unit 2 (with the exception of Braidwood, Unit 2), is the only pressurized-water reactor plant that is operating with an inoperable (un-tensioned) closure stud and the only one that has a stud left in place and inoperable.

Issue:
The applicant's discussion of plant-specific operating experience regarding its closure stud does not fully address how the applicant's plant-specific operating experience is bounded by industry operating experience as considered in AMP XI.M3 of the GALL Report. The staff noted that LRA AMP B2.1.3, "Reactor Head Closure Stud Bolting," may not be applicable, and a plant-specific AMP may be necessary in light of the plant-specific operating experience.

Request:
Justify how the plant-specific operating experience is bounded by the industry operating experience as considered in AMP XI.M3 of the GALL Report. As alternatives, either provide revisions to your AMP with associated reasoning, or provide a plant-specific AMP to manage aging effects of the reactor vessel head closure studs during the period of extended operation.

Exelon Response:

During the development of the Reactor Head Closure Stud Bolting (B.2.1.3) aging management program, a review of plant-specific operating experience was performed to confirm that the NUREG 1801, Revision 2, XI.M3, "Reactor Head Closure Stud Bolting" program is adequate to manage previously experienced aging effects, if any. During this review, the plant-specific operating experience related to Byron Unit 2 stud 11 and Braidwood Unit 2 stud 35 was identified and dispositioned as not age-related. However, upon further review it has been determined that the current configuration at Byron Unit 2 (e.g., operating with an un-tensioned closure stud which is left in place during refueling outages) was not considered in AMP XI.M3 of the GALL Report. Therefore, in response to this RAI, the ten (10) elements of NUREG 1801, Revision 2, XI.M3 were reviewed to determine if augmentation of the program is required to

adequately address the Byron and Braidwood configurations. Further, the Reactor Head Closure Stud Bolting (B.2.1.3) aging management program implementing procedures have been evaluated to determine if existing program procedures fully address Byron and Braidwood's plant-specific operating experience and fully address aging management of Byron Unit 2 stud 11 and Braidwood Unit 2 stud 35 or if enhancements to the existing program are required.

The evaluation has concluded that an additional enhancement to the Byron and Braidwood Reactor Head Closure Stud Bolting (B.2.1.3) aging management program is appropriate to ensure adequate aging management of the reactor head closure studs, and associated components, during the period of extended operation. With the addition of the new enhancement described below, the existing program procedures with the enhancement previously described in the license renewal application, fully address Byron and Braidwood's plant-specific operating experience and the configuration of Byron Unit 2 stud 11 and Braidwood Unit 2 stud 35.

Documented below is a summary of the evaluation of the ten (10) elements of NUREG 1801, Revision 2, XI.M3.

<u>Evaluation of Elements 1, "Scope of Program", 5, "Monitoring and Trending", 6, "Acceptance Criteria", 7, "Corrective Actions", 8, "Confirmation Process", and 9 "Administrative Controls"</u>

The evaluation concluded that existing program procedures fully address Byron and Braidwood's plant-specific operating experience and the configuration of the Byron Unit 2 stud 11 and the Braidwood Unit 2 stud 35, as well as all other reactor head closure studs, nuts, washers, and reactor vessel flange holes. No enhancement to existing BBS Reactor Head Closure Stud Bolting (B.2.1.3) program procedures is required for these elements in order to provide reasonable assurance that aging will be managed such that intended functions are maintained consistent with the current licensing basis through the period of extended operation. The recommendations provided in these elements of AMP XI.M3 of the GALL Report are applicable to the plant-specific operating experience and conditions at Byron and Braidwood without augmentation.

<u>Evaluation of Element 2, "Preventive Actions", Element 3, "Parameters Monitored/Inspected", and Element 4, "Detection of Aging Effects"</u>

The reactor disassembly and assembly procedures provide specific instructions intended to prevent, inspect for, and detect aging effects of the reactor vessel flange holes in which the associated stud is removed during refueling outage. These instructions include the following actions:

- After each stud is removed from the reactor vessel flange stud hole, each hole is cleaned, inspected, lubricated, and plugged prior to reactor cavity flood-up. This practice is intended to prevent borated water and foreign material from entering the reactor vessel flange stud holes, including the Braidwood Unit 2 reactor vessel flange stud 35 hole, and mitigates corrosion and wear.

- Immediately after the reactor head is lifted, the reactor vessel flange and "O-rings" are inspected for grooves, steam cuts, oxidation, and boric acid crystals. This inspection is adequate to detect signs of corrosion and physical damage to the reactor vessel and reactor head flanges.

- Prior to installing the reactor head closure studs into the reactor vessel flange and after the reactor cavity is drained, borated water is removed from all stud plug relief areas and the areas are cleaned. The plugs are then removed and the reactor vessel flange holes are again inspected. If borated water has leaked past a plug the borated water is removed and the hole is cleaned. This practice will detect and remove borated water from all reactor vessel flange stud holes, including the Braidwood Unit 2 vessel flange stud 35 hole, and mitigate corrosion and wear.

Based on the evaluation above, the existing reactor disassembly and assembly procedures include sufficient preventive actions and inspections to manage aging of the reactor vessel flange hole corresponding to Braidwood Unit 2 stud 35 as well as all other vessel flange holes for all four units, except for Byron Unit 2 stud 11.

However, augmentation to elements 2, 3, and 4 of the GALL Report is appropriate for configurations where a reactor head closure stud is left in the reactor vessel flange when the reactor cavity is flooded and the stud is exposed to borated water, such as Byron Unit 2 stud 11. The augmentation of elements 2, 3, and 4 of the GALL Report program will be implemented through a new enhancement to the program. If a reactor head closure stud remains in the reactor vessel flange and is exposed to borated water during refueling activities, the enhanced program will require the performance of ultrasonic examinations of the area around the reactor vessel flange hole. This new enhancement will require ultrasonic examination of the area around the reactor vessel flange holes for such studs, including Byron Unit 2 stud 11, once each ISI program period in accordance with the methodology in ASME Section XI, Table IWB-2500-1 item number B6.40 and examination requirement in Figure IWB-2500-12. This ASME examination requirement prescribes the ultrasonic examination of a one (1) inch radial band 360 degrees around the reactor vessel flange hole. The ultrasonic examinations will be performed to detect flaw sizes which are indicative of significant loss of material and cracking and will confirm that the corrosion rates described in the response to RAI B.2.1.3-3 are conservative. Although ASME Section XI Table IWB-2500-1 requires this inspection once each ISI interval, an increased frequency of once each ISI program period will be implemented to ensure that any age-related degradation is detected in a timely manner.

In addition, if a stud and reactor vessel flange hole have been exposed to borated water during past refueling activities and the stud is subsequently removed from the reactor vessel flange, the enhanced program will require that prior to placing the stud back in service: 1) the area around the reactor vessel flange hole will be inspected in accordance with ASME Section XI and 2) the stud, nut, and washer will be inspected in accordance with ASME Section XI, or a new stud, nut, and washer will be installed.

In the specific case of the Byron Unit 2 stud 11, this enhancement will be applicable since the stud and reactor vessel flange hole have been subjected to borated water in spring 2010, fall 2011, and spring 2013 refueling outages and the stud cannot be reused, since the top five (5) inches of the stud were removed.

The Byron and Braidwood LRA Appendix A, Section A.2.1.3, and Appendix B, Section B.2.1.3, are revised to reflect this additional enhancement as shown in Enclosure B of

this letter. The Byron and Braidwood LRA Table A.5 Commitment List, Item 3, is also updated as shown in Enclosure C of this letter.

Elements 2, 3, and 4 were also considered within a broader scope of preventing, inspecting for, and detecting physical damage, as well as, cracking and loss of material of stud, nut, washer, and reactor vessel flange hole threads to minimize stuck studs during reactor disassembly and assembly. This evaluation concluded that the reactor assembly and disassembly procedures contain significant and substantial instructions to prevent, inspect, and detect cracking and loss of material, as well as, physical damage when each stud is removed, handled, stored, and reinstalled, therefore, minimizing the potential for an additional future stuck stud. For additional details, refer to the response to RAI B.2.1.3-1.

Evaluation of Element 10, Operating Experience

During the development of the Byron and Braidwood License Renewal Application, an operating experience review was performed for plant specific and industry operating experience. This included all documents referenced in NUREG 1801, Revision 2, XI.M3, "Reactor Head Closure Stud Bolting". The review concluded that the operating experience at Byron and Braidwood is bounded by operating experience for which the GALL Report program was evaluated. The 1991 event at Braidwood Unit 2 in which stud 35 became stuck and the 2010 event at Byron Unit 2 in which stud 11 became stuck were considered in the operating experience review. These events were concluded not to be due to aging (i.e., cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or loss of material due to wear or corrosion). Particular attention was given to the aging affect of loss of material due to wear. NUREG 1801, Revision 2, provides guidance in which: "wear occurs in components that experience intermittent relative motion, frequent manipulation, or in clamped joints where relative motion is not intended, but may occur due to a loss of the clamping force." Wear or galling caused by event driven physical damage (e.g., due to human error) is not age-related degradation. Based on this guidance the two events were concluded not to be due to loss of material due to wear.

In response to RAI B.2.1.3-1, Exelon performed a follow up operating experience review for Byron Units 1 and 2. This follow up review did not identify any events caused by aging effects such as cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or loss of material due to wear or corrosion. The 2010 Byron Unit 2 stuck stud 11 event was again considered in this review and it was concluded that there is reasonable confidence that the stud did not become stuck due to aging effects such as cracking due to stress corrosion cracking (SCC), intergranular stress corrosion cracking (IGSCC), or loss of material due to corrosion or wear. Refer to Exelon's response to RAI B.2.1.3-1 for additional details.

An NRC inspection related to operating with 53 Reactor Head Closure Studs on Byron Unit 2 took place during the week of October 28, 2013. Some issues were identified that required further evaluation and were entered into the corrective action program. Evaluations are currently in-progress. When these evaluations are complete, Exelon will inform the NRC of the impact, if any, on this RAI response.

RAI B.2.1.3-3, Byron Unit 2 Rx Closure stud 11, flange hole, and boric acid

Applicability:
Byron, Unit 2

Background:
During the audit when discussing the stuck Stud No. 11, the staff noted that the threads are not leak-tight and borated water may enter into the flange hole bottom space during refueling outages. The staff also noted that the boric acid concentration may continually increase following each refueling outage and subsequent plant heat-up.

Issue:
Due to the stuck Stud No. 11 being stuck and left in place, the conditions at the location for the flange hole and the stuck stud are unknown. As a result, accelerated boric acid corrosion could occur and may go undetected.

Request:
Discuss the condition of Stud No. 11 and the flange hole. Explain how the AMP will detect and monitor boric acid corrosion for the stud and flange-hole.

Exelon Response:

The current condition of Byron Unit 2 reactor head closure stud 11 and the associated reactor vessel flange hole are described in the response to RAI B.2.1.3-1. Since the top five (5) inches of the stud have been removed, this stud cannot be reused and a new stud would be installed if the remaining portion of stud 11 is removed in the future.

The reactor head closure studs are hollow (one (1) inch internal diameter) and have carbon steel plugs threaded into the bottom hollow section of the stud. The plugs are designed to have 1/16” diameter holes that allow pressure to equalize between the volume under the stud and the hollow volume inside the stud.

In 2010 after stud 11 became stuck, an Engineering evaluation was performed authorizing a configuration change in which 53 of 54 reactor head closure studs are required to be tensioned for plant operation. The supporting calculations concluded that the configuration meets the requirements of ASME Section III, 1971 edition with addenda through summer 1973.

Stud 11 is subjected to an environment of borated water during refueling outages when the reactor cavity is flooded. The reactor disassembly procedure requires the installation of a plug into the top of stud 11 to prevent borated water from entering the hollow center. However, there is the potential that borated water will migrate through the reactor vessel flange and stud threads and accumulate in the volume under the stud. The potential for boric acid corrosion in these areas has been evaluated and it is concluded that the potential corrosion is insignificant and is bounded by a previous analysis as discussed below. This conclusion can be made primarily due to the small amount of time in which these areas may be exposed to borated water during refueling outages. The evaluation is summarized below.

The evaluation assumes that aerated borated water at a temperature of 100°F and with a boric acid concentration of 2500 ppm migrates through the reactor vessel flange and stud threads,

fills the volume under the stud, and remains there for the duration of the refueling outage. This boric acid concentration corresponds to concentrations in the Refueling Water Storage Tank. At this concentration and temperature Figure 4-3 of the EPRI Boric Acid Corrosion Guidebook provides an estimated corrosion rate for carbon steel of seven (7) mils per year. Given that a typical refueling outage lasts approximately 25 days or less, the estimated material loss prior to startup is insignificant, or 0.5 mils.

During reactor startup, less than one (1) gallon of borated water trapped under the stud will heat up and boil off as the reactor vessel heats up. As some of the water boils off, the boric acid concentration in the liquid state left behind will increase. Based on Figure 4-3 of the EPRI Boric Acid Corrosion Guidebook a reasonable corrosion rate for the concentrated boric acid while boiling is 1000 mils per year. A reasonable estimated duration for the borated water to completely boil off is ten (10) hours. The estimated amount of material loss during this ten (10) hour boil off period, assuming a corrosion rate of 1000 mils per year, is approximately 1.1 mils. After the boil off and all water is removed, the remaining boric acid will have a negligible corrosion effect on the carbon steel, for the remainder of the operating cycle. The boric acid will remain until the next refueling outage when the reactor cavity is again flooded. Therefore, the estimated material loss for the initial operating cycle, including the refueling outage, is less than 1.6 mils. In comparison, the reactor vessel wall, between the reactor vessel inner diameter and the vessel stud hole, is a minimum of 6-5/8 inches thick with an additional 0.125 inches of cladding.

The above corrosion rates identified from Figure 4.3 of the EPRI Boric Acid Corrosion Guidebook are based on testing where carbon steel samples were immersed in various water samples with different temperatures and boric acid concentrations with low pH values (e.g. pH of 4). At Byron, the refueling cavity is controlled to pH values greater than 6.5 under aerated conditions. The EPRI Boric Acid Corrosion Guidebook concludes that carbon steel exposed to borated water with the same concentrations and temperatures, but with the increased pH values of 6.5 or greater, will experience significantly reduced corrosion rates. Therefore, the estimated material loss documented above for the first refueling outage that a stud is left in place is a conservative estimate.

The potential for the concentration of the boric acid accumulating under the stud to increase each successive refueling outage has been considered and is concluded to be an insignificant contributor to corrosion. For example, the concentration of boric acid in the water that collects under the stud could potentially increase to 5000 ppm in the second refueling outage and to 7500 ppm in the third refueling outage. Theoretically, the boric acid concentration could increase by 2500 ppm each successive outage until the concentration reaches the solubility limit for boric acid in water at 100°F, which is approximately 13,000 ppm. This approximate concentration could be reached by the fifth refueling outage. Review of Figure 4-3 of the EPRI Boric Acid Corrosion Guidebook indicates that a bounding corrosion rate for boric acid with this concentration and temperature is 25 mils per year. This corrosion rate over approximately 25 days while the reactor cavity is flooded would result in a material loss of approximately 1.7 mils, which is considered insignificant. The 1000 mils per per year corrosion rate, assumed during the first startup, is still reasonable for the 10 hour period in successive startups. The material loss for each successive refueling outage is estimated to be less than 2.8 mils, and the total accumulated material loss after the last refueling outage in the period of extend operation, assuming the corrosion began in 2010, is estimated to be less than 71 mils. Therefore, the maximum projected increase in the radius of the stud 11 reactor vessel hole due to potential

boric acid corrosion, by the last refueling outage in the period of extended operation is less than 71 mils. The additional conservatism considered above, in which reactor cavity water is maintained at pH values greater 6.5, reinforces the conclusion that the maximum increase in the radius of the stud 11 reactor vessel flange hole is less than 71 mils.

Analysis of the Braidwood Unit 2 stud 35 reactor vessel flange hole concluded that the radius of the reactor vessel flange hole radius can be increased by 375 mils and still meet the requirements of ASME Section III, 1971 edition with addenda through summer 1973. The design requirements for Braidwood Unit 2 reactor vessel and Byron Unit 2 reactor vessel are identical. Therefore, the maximum postulated radius increase of 71 mils in the Byron Unit 2 stud 11 reactor vessel flange hole is considered insignificant and bounded by the previous Braidwood Unit 2 reactor vessel flange hole analysis.

The response to RAI B.2.1.3-2 documents that the Reactor Head Closure Stud Bolting (B.2.1.3) aging management program will be enhanced to require ultrasonic examination of the area around the reactor vessel flange stud hole once each ISI program period in accordance with the methodology in ASME Section XI, Table IWB-2500-1, item number B6.40 for reactor head closure studs that are not removed from the reactor vessel flange when the reactor cavity is flooded and are exposed to borated water. In addition, the program will be enhanced to require that when a stud that was not removed from the reactor vessel flange during prior refueling outages and was exposed to borated water and is subsequently removed from the reactor vessel flange, then prior to placing the stud back in service 1) the reactor vessel flange hole will be inspected in accordance with ASME Section XI and 2) the stud, nut, and washer will be inspected in accordance with ASME Section XI or a new stud, nut, and washer will be installed.

The new enhancement will require ultrasonic examination of the Byron Unit 2 stud 11 reactor vessel flange hole each refueling outage in accordance with the methodology in ASME Section XI, Table IWB-2500-1, item number B6.40, per examination requirement in Figure IWB-2500-12 while the stud remains out of service. This ASME examination requirement prescribes the ultrasonic examination of a one (1) inch radial band 360 degrees around the reactor vessel flange hole. The ultrasonic examinations will be performed to detect cracking and loss of material that may occur and would confirm that the corrosion rates described above are conservative. Although ASME Section XI Table IWB-2500-1 requires this inspection once each ISI interval, an increased frequency of once each ISI program period will be implemented to ensure that any age-related degradation is detected in a timely manner.

In conclusion, although the evaluation above demonstrates that predicted loss of material due to boric acid corrosion will not impact component intended functions, the enhanced program will include inspection activities capable of detecting cracking and loss of material of the reactor vessel flange to ensure component intended functions are maintained consistent with the current licensing basis through the period of extended operation.

An NRC inspection related to operating with 53 Reactor Head Closure Studs on Byron Unit 2 took place during the week of October 28, 2013. Some issues were identified that required further evaluation and were entered into the corrective action program. Evaluations are currently in-progress. When these evaluations are complete, Exelon will inform the NRC of the impact, if any, on this RAI response.

Enclosure B

Byron and Braidwood Stations, Units 1 and 2
License Renewal Application (LRA) updates resulting from the responses to the following RAIs:

RAI 2.1.5.2-1
RAI B.2.1.3-2

Note: To facilitate understanding, portions of the original LRA have been repeated in this Enclosure, with revisions indicated. Existing LRA text is shown in normal font. Changes are highlighted with ***bolded italics*** for inserted text and ~~strikethroughs~~ for deleted text.

As a result of the response to RAI 2.1.5.2-1 provided in Enclosure A of this letter, the Environments section of LRA Section 3.3.2.1.16, Heating Water and Heating Steam System is revised as follows:

Environments
The Heating Water and Heating Steam System components are exposed to the following environments:

- ***Air – Indoor Uncontrolled***
- Air with Borated Water Leakage
- Closed Cycle Cooling Water
- Closed Cycle Cooling Water > 140°F
- Condensation
- Waste Water

As a result of the response to RAI 2.1.5.2-1 provided in Enclosure A of this letter, LRA Table 3.3.2-16, "Heating Water and Heating Steam System - Summary of Aging Management Evaluation", is revised as follows:

Table 3.3.2-16 Heating Water and Heating Steam System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	***Air – Indoor Uncontrolled (External)***	***Loss of Material***	***Bolting Integrity (B.2.1.9)***	***VII.I.AP-125***	***3.3.1-12***	***A***
				Loss of Preload	***Bolting Integrity (B.2.1.9)***	***VII.I.AP-124***	***3.3.1-15***	***A***
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-102	3.3.1-9	A
					Bolting Integrity (B.2.1.9)	VII.I.AP-125	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VII.I.AP-124	3.3.1-15	A
Heat Exchanger - (Type 1 thru Type 6 Unit Heaters) Tubes	Leakage Boundary	Copper Alloy with less than 15% Zinc	***Air – Indoor Uncontrolled (External) (Byron Only)***	***None***	***None***	***VII.J.AP-144***	***3.3.1-114***	***C***
			Air with Borated Water Leakage (External)	None	None	VII.J.AP-11	3.3.1-115	C
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-199	3.3.1-46	C

Table 3.3.2-16 Heating Water and Heating Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	***Air – Indoor Uncontrolled (External)***	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-77***	***3.3.1-78***	***A***
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Closed Cycle Cooling Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.B1.S-08	3.4.1-1	A, 2
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.8)	VIII.D1.S-16	3.4.1-5	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A

Table 3.3.2-16 Heating Water and Heating Steam System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Stainless Steel	***Air – Indoor Uncontrolled (External)***	***None***	***None***	***VII.J.AP-17***	***3.3.1-120***	***A***
			Air with Borated Water Leakage (External)	None	None	VII.J.AP-18	3.3.1-120	A
			Closed Cycle Cooling Water > 140 F (Internal)	Cracking	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-186	3.3.1-43	A
				Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-49	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-95	A
Valve Body	Leakage Boundary	Carbon Steel	***Air – Indoor Uncontrolled (External)***	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-77***	***3.3.1-78***	***A***
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A

As a result of the response to RAI B.2.1.3-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.3, page A-11 is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

A.2.1.3 Reactor Head Closure Stud Bolting

The Reactor Head Closure Stud Bolting aging management program is an existing preventive and condition monitoring program that provides for preventive and condition monitoring activities to manage reactor head closure studs and associated RPV head flange threads, nuts, and washers for cracking and loss of material. The program is implemented through station procedures based on the examination and inspection requirements specified in ASME Code, Section XI, Table IWB-2500-1 and preventive measures to mitigate cracking. The program also relies on recommendations to address reactor head stud bolting aging-related degradation delineated in NUREG-1339 and NRC Regulatory Guide 1.65.

The Reactor Head Closure Stud Bolting aging management program will be enhanced to:

1. Revise the procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi.

2. ***Take the following actions to address reactor head closure studs that are not removed from the reactor vessel flange when the reactor cavity is flooded and are therefore exposed to borated water:***

   a. ***Revise the reactor vessel disassembly procedures to require ultrasonic examinations of the area around the reactor vessel flange stud hole once each ISI program period in accordance with the methodology in ASME Section XI, Table IWB-2500-1, item number B6.40 and examination requirement IWB-2500-12.***

   b. ***When a reactor head closure stud is removed from the reactor vessel flange, then prior to placing the stud back in service:***

      1. ***Inspect the area around the reactor vessel flange hole in accordance with ASME Section XI, Table IWB-2500-1, and***

      2. ***Inspect the stud, nut, and washer in accordance with ASME Section XI Table IWB-2500-1 or install a new stud, nut, and washer.***

~~This~~***These*** enhancement***s*** will be implemented prior to the period of extended operation.

As a result of the response to RAI B.2.1.3-2 provided in Enclosure A of this letter, the Reactor Head Closure Stud Bolting aging management Program Description sub-section of LRA Section B.2.1.3 is revised on page B-29 as shown below. The final paragraph from the existing LRA Program Description is shown, and a new paragraph is added to the end of this LRA sub-section as indicated with ***bolded italics.***

> In addition, the configuration of the reactor vessel in-service studs, nuts, and washers is designed to allow them to be completely removed during each refueling outage and placed in storage racks on the containment operating deck. The stud holes in the RPV head flange are sealed with special plugs before removing the reactor head. Thus, the bolting materials and stud holes are not exposed to the borated refueling cavity water.
>
> ***Operating experience has shown that occasionally reactor head closure studs become stuck and are not removed from the reactor cavity during refueling outages. Under these conditions, surfaces of the stud above the vessel flange are exposed to borated water and surfaces of the stud inside the reactor vessel flange hole and surfaces of the flange hole may be subjected to a borated water environment. Therefore, an enhancement has been added to the Reactor Head Closure Stud Bolting aging management program to address reactor head closure studs that are not removed from the reactor cavity when flooded during a refueling outage.***

As a result of the response to RAI B.2.1.3-2 provided in Enclosure A of this letter, the Reactor Head Closure Stud Bolting aging management program Enhancements sub-section of LRA Section B.2.1.3 is revised on page B-31 as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

1. Revise the procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi. **Program Element Affected: Preventive *Actions*~~Measures~~ (Element 2) and Corrective Actions (Element 7)**.

2. Take the following actions to address reactor head closure studs that are not removed from the reactor vessel flange when the reactor cavity is flooded and are therefore exposed to borated water:

   a. Revise the reactor vessel disassembly procedures to require ultrasonic examinations of the area around the reactor vessel flange stud hole once each ISI program period in accordance with the methodology in ASME Section XI, Table IWB-2500-1, item number B6.40 and examination requirement IWB-2500-12.

   b. When a reactor head closure stud is removed from the reactor vessel flange, then prior to placing the stud back in service:

      1. Inspect the area around the reactor vessel flange hole in accordance with ASME Section XI, Table IWB-2500-1, and

      2. Inspect the stud, nut, and washer in accordance with ASME Section XI Table IWB-2500-1 or install a new stud, nut, and washer.

   Program Element Affected: Preventive Actions (Element 2), Parameters Monitored/Inspected (Element 3), and Detecting Aging Effects (Element 4).

Enclosure C

Byron and Braidwood Stations (BBS) Units 1 and 2
License Renewal Commitment List Changes

This Enclosure identifies commitments made in this document and is an update to the Byron and Braidwood Station (BBS) LRA Appendix A, Table A.5 License Renewal Commitment List. Any other actions discussed in the submittal represent intended or planned actions and are described to the NRC for the NRC's information and are not regulatory commitments. Changes to the BBS LRA Appendix A, Table A.5 License Renewal Commitment List are as a result of the Exelon response to the following RAI:

RAI B.2.1.3-2

Notes:

- To facilitate understanding, portions of the original License Renewal Commitment List have been repeated in this Enclosure, with revisions indicated.
- Existing LRA text is shown in normal font. Changes are highlighted with ***bold italics*** for inserted text and ~~strikethroughs~~ for deleted text.

As a result of the response to RAI B.2.1.3-2, Item 3 on page A-70 of the License Renewal Commitment List is revised to add enhancement 2 as shown below. The RAI that led to this commitment modification is listed in the "SOURCE" column. Any other actions described in this submittal represent intended or planned actions. They are described for the NRC's information and are not regulatory commitments.

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
3	Reactor Head Closure Stud Bolting	Reactor Head Closure Stud Bolting is an existing program that will be enhanced to: 1. Revise the procurement requirements for reactor head closure stud material to assure that the maximum yield strength of replacement material is limited to a measured yield strength less than 150 ksi. ***2. Take the following actions to address reactor head closure studs that are not removed from the reactor vessel flange when the reactor cavity is flooded and are therefore exposed to borated water:*** ***a. Revise the reactor vessel disassembly procedures to require ultrasonic examinations of the area around the reactor vessel flange stud hole once each ISI program period in accordance with the methodology in ASME Section XI, Table IWB-2500-1, item number B6.40 and examination requirement IWB-2500-12.*** ***b. When a reactor head closure stud is removed from the reactor vessel flange, then prior to placing the stud back in service:*** ***1. Inspect the area around the reactor vessel flange hole in accordance with ASME Section XI, Table IWB-2500-1, and*** ***2. Inspect the stud, nut, and washer in accordance with ASME Section XI Table IWB-2500-1 or install a new stud, nut, and washer.***	Program to be enhanced prior to the period of extended operation.	Section A.2.1.3 ***Exelon letter RS-13-247 RAI B.2.1.3-2***