NRC-005-R

October 29, 2015

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

In the Matter of	)	
	)	
NUCLEAR INNOVATION NORTH	)	
AMERICA LLC	)	Docket Nos. 52-012 & 52-013
	)	
(South Texas Project, Units 3 and 4)	)	

NRC STAFF RESPONSES TO COMMISSION PRE-HEARING QUESTIONS

Pursuant to the Commission's "Order (Transmitting Pre-Hearing Questions)" of October 16, 2015, the staff of the U.S. Nuclear Regulatory Commission hereby responds to the questions posed in that Order. These questions generally pertain to subjects discussed in the staff's final safety evaluation report (SER)[1] or final environmental impact statement (FEIS).[2]

The Commission's Order directed some questions only to the staff, some questions only to Nuclear Innovation North America LLC (the applicant), and some to both the staff and the applicant. The attachment to this filing presents the staff's responses. In addition, the staff is informing the Commission through this filing that the staff discovered a minor inconsistency in the FEIS during the staff's prehearing preparation activities. Specifically, in Table 10-1 on page 10-5 of the FEIS, the socioeconomic physical impacts were reported as SMALL to MODERATE. That impact level should have been SMALL, consistent with the text and tables from Chapter 4,

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[1] Final Safety Evaluation Report for the South Texas Project Units 3 and 4 Combined License Application (Sept. 29, 2015).

[2] NUREG-1937, Environmental Impact Statement for Combined Licenses (COLs) for South Texas Project Electric Generating Station Units 3 and 4; Final Report (Feb. 2011).

"Construction Impacts at the Proposed Site." The staff's recommendation is not affected by this inconsistency.

Respectfully submitted,

/Signed (electronically) by/
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Dated at Rockville, Maryland
this 29th day of October 2015

ATTACHMENT

Staff Responses to Commission Pre-Hearing Questions

NRC STAFF RESPONSES TO COMMISSION QUESTIONS

1. There are a number of departures from the ABWR certified design and exemptions from NRC regulations. What consideration did the Staff give to any cumulative impacts from these departures and exemptions?

Staff Response: The U.S. Advanced Boiling Water Reactor (ABWR) design was certified in 1997, a full decade before the South Texas Project (STP) application was docketed. It is reasonable to expect that improvements in technology and innovations in design will occur over such a period and that these improvements and innovations will result in proposed design changes. In much the same way, changes and improvements to operating plants are proposed as technology evolves. In both cases, the Commission's regulations anticipated and allowed for such design changes. In the case of Tier 1 and generic technical specification (TS) departures, specific staff permission in the form of an exemption is required. For Tier 2* departures, prior NRC approval is required. In the case of Tier 2 departures, the applicant may make the change without prior NRC approval provided that specific regulatory criteria are met. The staff reviewed all departures to ensure that the applicant has adhered to the applicable regulatory criteria.

When evaluating departures from a certified design, the staff uses a systemic approach; that is, a change to a pump, valve, control circuit, or piping system is not evaluated in isolation. The review may require the coordination of engineers in various disciplines in order to ensure that the impacts of a given departure are evaluated in their totality.

In addition, the applicant evaluated the cumulative change in risk from its departures; the staff determined that the cumulative impact is not a significant change to core damage frequency (CDF) and large release frequency (LRF).

For the exemptions from regulations associated with material control and accounting and financial qualifications, the staff followed the requirements of 10 CFR 52.7 and documented its evaluations and findings in Chapter 1 of the final safety evaluation report (SER). The staff believes that there are no cumulative impacts from the granting of these exemptions.

2. In order for the NRC to certify a design, the design must be "essentially complete." 10 C.F.R. § 52.41. When promulgating Part 52, the Commission stated that the phrase "essentially complete nuclear power plant . . . is defined as a design which includes all structures, systems, and components which can affect safe operation of the plant except for site-specific elements . . . ." Final Rule: Early Site Permits; Standard Design Certifications; and Combined Licenses for Nuclear Power Reactors, 54 Fed. Reg. 15,372, 15,382 (Apr. 18, 1989). NINA is proposing to take over 300 departures from the certified ABWR design.

Given the large number of departures, is this application still referencing an essentially complete certified design, or should the design being referenced in the combined license (COL) application be considered a unique design?

Staff Response: The STP Units 3 and 4 design should not be considered a unique, or custom, design. The NRC discussed the "custom design" concept in its 2008 final policy statement entitled "Conduct of New Reactor Licensing Proceedings," 73 FR 20963, 20965 (Apr. 17, 2008):

> Part 52 has never required an applicant for a COL to reference a certified design. Rather, a COL applicant has always had the option of requesting a COL for a design that is not certified under Part 52, Subpart B (a ''custom'' plant).

As this discussion makes clear, a custom plant is one in which the COL applicant does not reference a certified design. The STP application, however, references the certified ABWR design and satisfies the requirements for referencing that design. Therefore, Nuclear Innovation North America LLC (NINA) should be afforded the regulatory benefits accruing from this choice. Also, NRC regulations do not limit the number of departures that can be taken from a certified design. Section VIII of 10 CFR Part 52, Appendix A imposes requirements for COL applicants seeking to depart from the ABWR design, but the applicant has satisfied these requirements, as discussed in the final SER.

In addition, the term "essentially complete" appears three times in 10 CFR Part 52: 10 CFR 52.41(b)(1), 52.47(c)(1), and 52.47(c)(2). In each case, the requirement for an "essentially complete" design applies to design certification applications and not to COL applications. Nonetheless, the design for STP Units 3 and 4 is complete, not just essentially complete. That is, the design for STP Units 3 and 4 includes all structures, systems, and components which can affect safe operation of the plant, *including* site-specific elements. This complete design is based on the certified ABWR design, the departures taken by NINA, and the site-specific design elements that NINA supplied in its application.

3. Condition 2.d.(12)(d) in the draft COL addresses the transportation physical security plan. Paragraph 2 of that condition requires NINA to update FSAR § 13.6.4, in its first FSAR update after issuance of the license.

If the required information can be provided with the first FSAR update, why can it not be provided now?

Further, the license condition states that the FSAR update should include requirements to meet 10 C.F.R. § 74.15, but does not provide specifics on how the licensee must meet those requirements.

Explain how this license condition meets the Commission's requirement that conditions be "precisely drawn so that the verification of compliance becomes a largely ministerial act." ***Private Fuel Storage, LLC*** **(Independent Spent Fuel Storage Installation), CLI-00-12, 52 NRC 23, 34 (2000).**

Staff Response: The license condition describes several requirements in 10 CFR 73.67(g) and actions to be taken by the licensee for receipt inspection of new fuel. The staff identified the need for this additional information after the submission of Revision 12 of the Final Safety Analysis Report (FSAR), and considered it prudent to include these in the FSAR to ensure that these requirements were understood and the necessary actions will be taken. The applicant addressed this additional information in a letter dated July 7, 2015, (ML15194A054), which provided commitments to address the requirements in 10 CFR 73.67(g) and 10 CFR 74.15. However, the applicant did not wish to update the FSAR prior to COL issuance because the administrative requirements involved in an FSAR update would have delayed the completion of the review. Given the minor nature of the additions, the staff decided that it is acceptable to have the FSAR updated after the COL is issued.

In describing the "ministerial act" standard for license conditions, the *Private Fuel Storage* decision states that the staff may exercise its professional judgment in post-licensing verifications, but "sufficient details should be provided in the license so that the staff's review is not subject to meaningful debate." *Private Fuel Storage*, CLI-00-12, 52 NRC at 34. The transportation physical security plan license condition meets this standard because verifying the licensee's compliance with 10 CFR 74.15 is not subject to meaningful debate. Note that section 13.6.4 in the FSAR is focused upon the transport of special nuclear material (SNM) and does not address the requirements of material control and accounting (MC&A) in detail. Also, the requirements of 10 CFR 74.15 are depicted clearly in the regulation and the applicant's means to meet those requirements have been reviewed comprehensively by the NRC staff. Specifically, 10 CFR 74.15 explicitly details the requirements for filling out and submitting a nuclear material transaction report. In addition, it lists the guidance to be used (NUREG/BR-0006 and Nuclear Material Management and Safeguards System (NMMSS) Report-D24, "Personal Computer Data Input for NRC Licensees"). Furthermore, in a July 15, 2011, submittal (ML11307A239), the applicant provided the proposed SNM MC&A program in Attachment 2 to encompass various MC&A requirements, including the reporting requirement of 10 CFR 74.15, "Nuclear material transaction reports." The staff concludes that the 74.15 reporting program is acceptable and meets the regulatory requirement. The staff's review is documented in the MC&A portions of Section 1.5S.5.8 on pages 1-73 to 1-74 of the final SER.

4. License condition 2.D.(14)(i) regarding Cyber Security states that "8 months before fuel is allowed onsite (within the protected area) NINA shall develop a written protective strategy . . ." to meet 10 C.F.R. § 73.54.

Please describe whether the Staff has found that all of the cyber security requirements necessary for licensing are met at this time.

Further, please address how this condition meets the Commission's requirement that conditions be "precisely drawn so that the verification of compliance becomes a largely ministerial act." ***Private Fuel Storage, LLC*** **(Independent Spent Fuel Storage Installation), CLI-00-12, 52 NRC 23, 34 (2000).**

<u>Staff Response</u>: Yes, the staff has found that all of the cyber security requirements necessary for licensing are met at this time. The staff determined that the cyber security plan includes all features considered essential to a cyber security program. The staff determined that the cyber security plan complies with the applicable Commission regulations.

The license condition relates to a specific time milestone for developing detailed implementing procedures for elements of the cyber security program prior to fuel onsite (protected area). A license condition for implementation of these elements of the cyber security program is unnecessary because overall implementation of the cyber security program is addressed by FSAR Section 13.4S and 10 CFR 73.55(a)(4).

This license condition adds a more specific milestone for certain elements of the cyber security program. The license condition was reviewed and accepted because the applicant demonstrated in sufficient detail compliance with the cyber security regulations. Providing design details after the issuance of the license is consistent with implementation of the cyber security program prior to operation of the facility. At the time, the license condition appeared reasonable and the staff did not have technical objections to a specific milestone that would provide greater detail for the planning of inspection activities.

As explained in the response to Question 3, the *Private Fuel Storage* decision states that the staff may exercise its professional judgment in post-licensing verifications, but "sufficient details should be provided in the license so that the staff's review is not subject to meaningful debate." *Private Fuel Storage*, CLI-00-12, 52 NRC at 34. In this case, the license condition functions to require the development of the written protection strategy at a time that will aid NRC inspection activities. These NRC inspection activities will be performed to confirm that the licensee has properly implemented its cyber security plan. As stated above, the applicant provided sufficient details in the plan to satisfy NRC regulations. As such, verification that this license condition is met will be a largely ministerial act, consistent with the test articulated in the *Private Fuel Storage* decision.

5. NINA would be the licensee responsible for design and construction of STP Units 3 and 4. STPNOC will be the operator and license holder for STP Units 3 and 4 upon issuance of the 10 C.F.R. § 52.103(g) finding or authorization for interim operation pursuant to 10 C.F.R. § 52.103(c). Describe how the transition to operation will take place. Will there be duplicate programs running in parallel, such as the corrective action program?

Response to be submitted by the applicant only.

6. The Staff's findings in § 1.4S of the Safety Evaluation Report (SER) regarding the alternate vendor qualifications requirements in 10 C.F.R. § 52.73 appear to rely in large part on findings from a 2009 inspection report.

Please describe in more detail what information, if any, is included in licensing basis documents to assure the applicant's continued ability to meet the requirements in 10 C.F.R. § 52.73 and Part 52, Appendix A.III.

Staff Response: As a consequence of choosing Toshiba as the vendor for STP Units 3 and 4, the applicant performed due diligence and documented this in a due diligence report. This due diligence included a complete assessment of Toshiba's ability to supply and support the ABWR design. The staff reviewed the applicant's due diligence report and evaluated the engineering and management capabilities of Toshiba, Inc. This review was more than a snapshot of Toshiba's ability to supply the design for the US certified ABWR at that time; rather, it was a systematic evaluation of Toshiba's ability to support the design as the original design vendor would have. The staff evaluated Toshiba's quality assurance program, subcontractor qualification procedures, and corrective action program. In addition, the staff evaluated Toshiba's ability to supply aspects of the design to which they may not have access. As documented in Section 1.4S of the final SER, the staff determined that Toshiba is qualified to fulfill vendor requirements throughout the life of the plant.

The applicant's process of conducting due diligence provides confidence that it is capable of assessing vendor qualification. If the applicant were to change design vendors in the future, the applicant would be required to change the final safety analysis report (FSAR), which would be subject to the NRC's change process regulations.

7. The FSAR provides that both Toshiba Power Systems Company and Shaw Group Incorporated, as part of the Consortium, in conjunction with subcontractors, are responsible for the Engineering, Procurement, and Construction (EPC) of STP Units 3 & 4.

a. **For NINA: Both Toshiba and Shaw are identified as responsible for the EPC. Please clarify.**

b. **For the Staff: Why is Shaw not discussed in the SER?**

Staff Response: The staff conducted an extensive review of Toshiba's engineering and engineering management operations. As part of that evaluation, the staff evaluated Toshiba's ability to qualify its contractors. Toshiba is the leader of the consortium and the staff's assessment of the capabilities of all of the members and contractors of the consortium is subsumed by its evaluation of Toshiba whether or not those members are specifically identified in the final SER.

8. **NINA requested an exemption from the current financial qualification requirements in 10 C.F.R. §§ 52.77, 50.33(f), and Part 50, Appendix C, to allow the use of a financial qualification standard similar to that in 10 C.F.R. Part 70, in accordance with the Staff Requirements Memorandum on SECY-13-0124, "Policy Options for Merchant (Non- Electric Utility) Plant Financial Qualifications," and the Draft Regulatory Basis for the proposed financial qualifications rulemaking. With its exemption request, the applicant addressed the standards in 10 C.F.R. §§ 52.7 and 50.12 and submitted an Applicant Financial Capacity Plan with proposed license conditions. The NRC Staff concluded that NINA's proposed license conditions (with minor revisions) meet the intent of the Draft Regulatory Basis. Please describe what actions would be required by the prospective licensee to satisfy the proposed financial qualification license conditions.**

Staff Response: Specifically, for construction, the proposed license condition states that:

> NINA shall notify the NRC at least 60 days prior to its anticipated date of construction that the license condition has been fulfilled and that the following are available for inspection:
>
> - An updated cost estimate;
> - Documentation justifying any material variances from the original cost estimate provided in the application; and
> - Documentation demonstrating that the licensee has secured financing to fund the updated cost estimate for the project. This documentation will include operative closing documents, and may include documented proof of parent and affiliate assurances, or capital from other sources (as required to close the financing) that reflect financing for the project.

In order to fulfill the license condition, the prospective licensee would need to make available for inspection documentation demonstrating how it arrived at its updated cost estimate to the extent it materially varies from the cost estimate in the application. For example, if the cost estimate had changed due to a change in the cost of rebar, the licensee would make available documentation noting the change. The degree of documentation expected is commensurate with the degree of change in the cost estimate. If the change in cost estimate is effectively the inflation rate from the time the application was submitted to the time construction is ready to commence, the staff would expect to see minimal documentation. The staff would expect to see more documentation for more significant changes to the construction cost estimate, particularly if the construction cost estimate is lower than the estimate at the time of application.

In order to demonstrate financing, the prospective licensee would need to make available for inspection documents describing its plans for financing the project. For example, if the prospective licensee was utilizing project financing, the prospective licensee would need to make available documents from the financial closing which demonstrates it has procured funding. If the prospective licensee was using its own funds to finance the project, the staff would expect to see documentation demonstrating the availability of its own funds.

The prospective licensee's documentation made available to the NRC for inspection in order to fulfill this condition should make it readily apparent that the funds for financing the project will meet or exceed the updated construction cost estimate.

For operation, the proposed condition states that:

> NINA shall notify the NRC at least 60 days prior to initial loading of fuel that the license condition has been fulfilled and that the following are available for inspection:
>
> - An updated cost estimate for each of the first 5 years of operations;
> - Documentation justifying any material variance from the original cost estimate provided in the application; and
> - Documentation of sources of funds to cover each of the first 5 years of operations. Such funds may come from, but are not limited to, power purchase agreements, parent assurances, and/or revenues from the anticipated sale of power.

In order to fulfill the license condition, the prospective licensee should make available for inspection documentation at a similar level of detail as discussed above in the construction cost estimate. Similar to the construction license condition, the prospective licensee should make available documents that indicate the methods they intend to use to cover operations costs. For example, if a prospective licensee has power purchase agreements in place that will cover the cost of operations, the prospective licensee would simply make available copies of those agreements. The documentation should make it readily apparent that the prospective licensee will have the funds to cover the first 5 years of operations.

The staff does not expect the documentation made available to fulfill these license conditions to be onerous.

9. Section 1.5S of the SER discusses the proposed exemption from the financial qualifications requirements in 10 C.F.R. Part 50. As directed by the Commission in the Staff Requirements Memorandum for SECY-13-0124, the Staff is anticipating the outcome of the forthcoming financial qualifications rulemaking as part of the basis for granting the exemption. In license condition 2.D.(14)(K)(1) in the draft combined license, paragraph (iii) states that "this documentation will include operative closing documents, and may include documented proof of parent and affiliate assurances... ."

What is the purpose of the "may" clause? Is it meant to convey permission from the NRC on the types of information allowed, or is it meant as an example of the type of information that may be submitted?

<u>Staff Response</u>: The "may" clause is intended to provide an example of the type of information that may be made available for inspection to the NRC. Precisely what is utilized depends on the nature of how the prospective licensee intends to finance construction. If part of the construction is to be financed using parent or affiliate assurances, then the staff would expect documentation of these assurances to be made available. However, if the financing does not include such assurances, the staff would not expect documentation of these assurances to be utilized to fulfill the license condition.

10. In promulgating 10 C.F.R. § 50.44, the Commission stated that paragraph (c) of the final rule sets forth combustible gas control requirements for all future water-cooled nuclear power reactor designs and "these requirements reflect the Commission's expectation that future designs will achieve a higher standard of severe accident performance." 50 Fed. Reg. 32,138 (Aug. 8, 1985). The Staff proposes elimination of the hydrogen recombiners requirements in STD DEP T1 2.14-1, finding special circumstances are present as described in 10 C.F.R. § 50.12(a)(2)(ii), which states that application of the regulation in the particular circumstances would not serve the underlying purpose of the rule or is not necessary to achieve the underlying purpose of the rule.

Given this departure proposed from the Standard ABWR Design, how does the South Texas Project Units 3 and 4 combined license application meet the Commission's statement quoted above when issuing 10 C.F.R. § 50.44 that future designs will achieve a higher standard of severe accident performance?

<u>Staff Response</u>: The ABWR design included hydrogen recombiners to mitigate a design basis accident as required by 10 CFR 50.44 as it existed at the time of certification. Studies performed since the ABWR design was certified have demonstrated that hydrogen recombiners of the size and quantity included in the ABWR design do not provide a safety benefit for severe accidents. The need for hydrogen recombiners at the time had been based on the risk from the hydrogen generated during a design basis LOCA, which could produce hydrogen from a 5 percent metal-water reaction involving fuel cladding. The NRC found that this hydrogen release was not significant, as documented in the statement of considerations for the 2003 rule revising 10 CFR 50.44. During this rulemaking, the NRC eliminated the requirement for hydrogen recombiners for design basis accidents.

For nuclear power plants licensed under 10 CFR Part 52, the NRC imposes additional requirements for containments beyond those for currently operating plants. This practice is consistent with the NRC's Severe Accident Policy Statement that new nuclear power plants should incorporate improvements during design and construction that were not practical or cost-effective to require as modifications to existing plants. Through the design certification review, the ABWR design included severe accident prevention and mitigation features.

10 CFR 50.44(c) provides for consideration of an amount of hydrogen generated equivalent to that produced by oxidation of 100 percent of the fuel cladding with steam. This section requires that new reactors licensed under Part 52 have a mixed atmosphere in containment; an inerted atmosphere, or a hydrogen concentration less than 10 percent; equipment survivability for those systems and components required to mitigate a severe accident; hydrogen and oxygen monitoring; and a structural analysis demonstrating containment integrity following a beyond design basis accident. The STP application meets all of these requirements. The ABWR severe accident design features result in STP Units 3 and 4 achieving a higher standard of severe accident performance.

See the staff's response to Question 56 for a list of ABWR severe accident design features.

11. Tier 1 departure 2.14-1 and the associated exemption request proposes to eliminate the flammability control system from the ABWR certified design. The SER states that the departure and exemption are justified because of changes to 10 C.F.R. § 50.44 that occurred after certification of the ABWR. However, § 50.44(c) states that it is applicable to design certifications issued after October 16, 2003. The ABWR was certified in 1997.

Please provide further explanation for why changes to § 50.44 justify the elimination of the flammability control system. Further, if the applicant is now relying on the current version of § 50.44, please discuss whether the combined license application must also meet the requirements of § 50.44(c)(1) and (5).

Staff Response: The ABWR flammability control system (FCS) consists of two redundant hydrogen recombiners located in the secondary containment. As discussed in staff's response to Question 10, the staff eliminated the requirement for hydrogen recombiners for design basis accidents when the NRC revised 10 CFR 50.44 in 2003.

STP Units 3 and 4 Tier 1 Departure 2.14-1 reflected the elimination of the requirement to maintain equipment needed to mitigate a design-basis LOCA hydrogen release, which included elimination of the ABWR FCS. With this elimination, the STP design is consistent with the requirements for combustible gas control in the updated 10 CFR 50.44, which was amended after the issuance of the DC for the ABWR.

The STP COL application must also meet the requirements of 10 CFR 50.44(c)(1) and (5). 10 CFR 50.44(c)(1) requires containment capability for ensuring a mixed atmosphere during design-basis and significant beyond design-basis accidents. In addition, 10 CFR 50.44(c)(5) requires a structural analysis which must address an accident that releases hydrogen generated from 100 percent fuel clad-coolant reaction accompanied by hydrogen burning. Systems necessary to ensure containment integrity must also be demonstrated to perform their function under these conditions.

With respect to 10 CFR 50.44(c)(1), the STP COL application complies with the mixed atmosphere requirements by a combination of active and passive capability to mix the atmosphere.

Staff concluded that the STP COL application complies with 50.44(c)(5) requirements for a structural analysis. Staff concluded that the requirements of 50.34(f)(3)(v)(A)(1), which are equivalent to the requirements of 50.44(c)(5), for maintaining containment integrity below ASME III Service Level C requirements for steel containments during an accident that releases hydrogen generated from 100 percent fuel-clad metal-water reaction are satisfied, as stated in ABWR final SER, NUREG-1503, Section 19.2.3.3.1.1.

12. Departure STD DEP T1.2.14-1 in the combined license application removes the Flammability Control System, which was part of the original ABWR design. The stated basis for removal of the system is that it is no longer required by the revision of 10 C.F.R. § 50.44 that occurred after the ABWR design was approved. Section 50.44 was revised because inerted containments provide protection from hydrogen combustion. The Fukushima event showed, however, that hydrogen combustion events can occur outside of the inerted primary containment and cause significant damage to the secondary containment building. Was the

possible benefit of the Flammability Control System in the context of severe accident mitigation and recovery considered with respect to removal of the System for the STP combined license application?

Staff Response: As discussed in the response to Question 10, studies performed since the ABWR design was certified have demonstrated that hydrogen recombiners of the size and quantity included in the ABWR design do not provide a safety benefit for severe accidents.

The ABWR FCS was designed to control the potential buildup of a combustible mixture of hydrogen and oxygen inside the containment during a design basis accident. The FCS is physically located outside the containment and is sized to address the combustible buildup of hydrogen and oxygen from a design basis metal water reaction and radiolysis of water during a loss of coolant accident. The severe accident amount of combustible hydrogen is much greater than the design basis assumptions used to size the FCS. Therefore, there is limited benefit in retaining the FCS, as designed, in support of a severe accident mitigation and recovery.

In addition, as discussed in response to Question 33a, the applicant's evaluation showed no significant leakage for containment penetrations below the Containment Overpressure Protection System (COPS) opening pressure of 0.72 MPa (approximately 90 psig). The use of 0.72 MPa as the setpoint for actuating COPS was approved in the ABWR certification. Upon actuation of COPS, the containment pressure is relieved through the plant stack, purging hydrogen from containment, avoiding containment failure and uncontrolled release of hydrogen to the reactor building.

13. In § 1.11S.1.3 of the SER, regarding STD DEP T1 2.14-1, the NRC staff states:

> **The containment hydrogen and oxygen monitoring functions of the Containment Monitoring System are no longer required to function for the mitigation of a design basis LOCA [loss of coolant accident]. Consequently, the containment hydrogen and oxygen monitoring functions are no longer classified as Category 1, as defined in Regulatory Guide (RG) 1.97, "Instrumentation for Light- Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 4. The RG 1.97 classification of containment hydrogen and oxygen monitoring functions are changed to Category 3 for hydrogen monitoring, and Category 2 for oxygen monitoring, allowing these instruments to be reclassified as nonsafety-related.**

Regulatory Guide 1.97, Revision 4 (June 2006), removed the terminology of Categories 1, 2, and 3 and instead provided performance-based criteria for use in selecting variables.

a. Please explain how the Staff applied Regulatory Guide 1.97.

b. Please explain how the Staff determined NINA's proposed hydrogen and oxygen monitors meet the criteria of 10 C.F.R. §§ 50.44 (c)(4)(i) and (c)(4)(ii).

c. Further, please explain the Staff's acceptance of the deletion of the words "during accident conditions" in reference to the monitors for oxygen levels in FSAR § 6.2.5.2.1.

Staff Response:

a) In the ABWR certification, the staff reviewed ABWR DCD Chapter 7.5 and confirmed that the post-accident monitoring (PAM) variables are based on RG 1.97, Revision 3. ABWR DCD chapter 7.5 is incorporated by reference in the STP Units 3 and 4 FSAR and the COL applicant did not use, and was not required to use, Revision 4. In the STP review the staff concluded that the containment hydrogen and oxygen monitoring functions of the containment monitoring system are no longer required to function for the mitigation of a design-basis LOCA, consistent with the 2003 revision of 10 CFR 50.44(c). Therefore, the classification of containment hydrogen and oxygen monitoring functions changed to Category 3 for hydrogen monitoring, and Category 2 for oxygen monitoring, allowing these instruments to be reclassified as nonsafety-related.

b) The Containment Atmospheric Monitoring System (CAMS) monitors hydrogen concentration and oxygen concentration in both the drywell and wetwell in accordance with 50.44(c)(4)(i) and 50.44(c)(4)(ii), which specifically require equipment to be provided for monitoring oxygen and hydrogen in containment. STP meets these requirements because the hydrogen and oxygen concentration sensors are located outside the primary containment and the sensors are designed to function during the expected severe accident conditions.

c) For STP Units 3 and 4, Departure T1 2.14-1, "Hydrogen Recombiner Requirements Elimination," the more restrictive language "during accident conditions" was removed because the CAMS monitors oxygen and hydrogen concentrations during all modes of operation, not just during accidents.

14. The acceptance criterion in RG 1.91 states that safety-related concrete structures are considered safe if the air overpressure from an explosion is below 1 pound per square inch (psi). The calculated hydrogen explosion air overpressure shown at the nearest safety-related systems, structures, and components (SSCs) in FSAR Table 2.2S-10, Revision 12 is 0.987 psi. Because this value is so close to 1 psi, did the Staff or NINA perform any additional analysis to demonstrate the safety of safety- related SSCs? If so, what were the results?

Staff Response: The staff did not perform any additional analysis and determined that such an analysis was not necessary due to the conservatisms in the development of the 1-psi criterion as well as the design margin in safety-related SSCs. Based on overpressure damage estimates from incident observations, a 1-psi incident overpressure would result in only partial demolition of wood frame structures, some window frame damage, and usually the shattering of windows. Therefore, the 1-psi criterion is a conservative estimate, below which the safety-related SSCs would not be affected. Also, the safe distance to a 1-psi overpressure due to a potential vapor cloud explosion of hydrogen (Table 2.2s-10) is determined based on conservatively assuming the entire contents of the hydrogen tank were released directly over a 10-minute period, and also using conservative meteorological conditions of 1 m/sec with atmospheric stability class F for dispersion calculations for ALOHA modeling. As such, a 1-psi calculated potential explosion based on conservative assumptions contains a reasonable margin of safety and, therefore, a more rigorous additional analysis is neither required nor warranted to demonstrate the safety of safety-related SSCs.

15. a. For the Staff and NINA: Does the annual tornado strike frequency (or, recurrence interval) of 1.75E-04 provided in SER Section 2.3S.1.4.3.2 correspond to the strike frequency for one of the units, both of the units

combined, or individual structures within a unit? If it is for an individual structure, what is the annual tornado strike frequency for each unit?

b. **For the Staff and NINA: It appears NINA used the characteristic dimension of 200 feet (ft) from NUREG/CR-4461, Rev. 2 when calculating annual tornado strike frequency. But some structures for STP Units 3 and 4 appear to have dimensions greater than 200 ft (e.g., Figure 1, RAI Response 03.05.01.06-1). Why is it reasonable to use the 200 ft characteristic dimension provided in NUREG/CR-4461?**

Staff Response:

a. The annual tornado strike frequency (or, recurrence interval) of 1.75 E-4 provided in final SER Section 2.3S.1.4.3.2 corresponds to the strike frequency for an individual structure with a characteristic dimension of 200 feet.

The response to RAI 03.05.01.06-1 described NINA's method for calculating the probability of an aircraft crashing into one of the two units at STP Units 3 and 4. In implementing this methodology, NINA conservatively estimated that the diagonal length of a rectangle drawn to include all of the safety-related structures for one unit at STP (e.g., the reactor building, the control building, the ultimate heat sink, and the UHS pump house) was 778 feet. The annual tornado strike frequency at the STP site for each unit assuming a dimension of 778 feet for the unit is estimated to be 3.33 E-4.

b. The design-basis for each safety-related structure is based on the tornado strike frequency for a characteristic structure. The design-basis wind speeds are then estimated as a function of this strike frequency to ensure an overall exceedance frequency of 1 E-7 per year. Specifically, tornado strike frequencies are estimated as a function of the characteristic building dimensions. The diagonal lengths for the four largest safety-related structures at the STP site (the reactor building, the control building, the ultimate heat sink, and the ultimate heat sink pump house) range from 169 feet to 326 feet. The annual tornado strike frequency at the STP site, assuming structural dimensions of 169 feet and 326 feet, are estimated to be 1.67 E-4 and 2.10 E-4, respectively. These ranges in tornado strike frequencies show that the use of a characteristic building dimension of 200 feet is a reasonable mean value for estimating the annual tornado strike frequency for the safety-related structures at the STP site.

16. 10 C.F.R. § 100.23(c) requires NINA to investigate the geological and seismological characteristics of the STP site and its environs to support estimates of the Safe Shutdown Earthquake Ground Motion, among other things. Hydrocarbon extraction in the Eagle Ford Shale in South Texas may now be more extensive than it was at the time the FSAR and SER were developed.

For NINA: Does the recent extraction of hydrocarbons in the Eagle Ford Shale change NINA's response to RAI 0.2.05.01-14 (August 27, 2008) related to the potential for future subsidence due to human activities and effects from these activities?

For the Staff: Does the recent extraction of hydrocarbons in the Eagle Ford Shale change the Staff's assessment of Effects of Human Activities (under Site Engineering Geology Evaluation in Section 2.5S.1.4.2 Site Area Geology)?

Staff Response: Hydrocarbon extraction from the Eagle Ford Shale in portions of South Texas does not change the staff's assessment of the effects of human activities at the STP COL application site. Hydrocarbon extraction from shale or hydrofracking can potentially affect a site by causing site subsidence or by triggering earthquakes. However, the STP site is located south of Bay City, TX in Matagorda County, which is approximately 100 miles from the eastern edge of the Eagle Ford Shale productive area (Lavaca County), at its closest proximity. Given the distance between the STP site and the nearest productive area of the Eagle Ford Shale, recent extraction would not impact the STP site by subsidence because subsidence mainly has local effects. In addition, the amplitude of the design earthquake ground motion for STP is much higher than the potential amplitude of the earthquake ground motion that could be triggered by hydrofracking activities. Hydrofracking related earthquakes are relatively small magnitude and distant from the STP site. Consequently, they will have no significant effect on the design of the safety-related structures, systems and components at STP.

Given the depth and thickness of the Eagle Ford Shale beneath the STP site, the staff does not expect that future extraction near the site would be likely. As the Eagle Ford Shale formation extends eastward towards the coastal shelf, it is overlain by thick, younger Coastal Plain sediments and is believed to thin considerably. These younger, overlying Coastal Plain sediments are more than 26,000 feet thick beneath the STP site. Hydrocarbon extraction from the Eagle Ford Shale is not likely near the STP site as these activities are typically limited to productive units at much shallower depths. Even if extraction did occur at the STP site, it would have to be at depths greater than 26,000 feet, and therefore would not impact the STP site.

17. As noted in Section 2.5S.2.4.4 of the SER, NINA compared the results of probabilistic seismic hazard analysis (PSHA) calculations for two of six Electric Power Research Institute-Seismicity Owners Group (EPRI-SOG) earth science teams (ESTs) source models as part of its PSHA software validation. The Staff issued RAI 02.05.02-11 regarding NINA's PSHA software validation. In response, NINA provided a comparison of calculations for all six EPRI-SOG ESTs. The SER notes significant differences in the validation results between the original 1989 EPRI-SOG PSHA calculation and NINA's PSHA calculation used for the combined license application for all the ESTs except for the Bechtel and Weston ESTs. Describe the process used by the Staff to review the validation results for the PSHA software.

Staff Response: NINA's contractor developed probabilistic seismic hazard analysis (PSHA) software that complies with 10 CFR Part 50, Appendix B. This new software included an update to the original EPRI-SOG source model and was used to develop the seismic hazard curves and Ground Motion Response Spectrum (GMRS) for the STP site. The GMRS was used to establish the licensing basis for STP Units 3 and 4.

To further verify the accuracy and validity of the software used for the PSHA, NINA used its software to reproduce the results of the original 1989 EPRI-SOG PSHA calculations for the STP site. These comparisons of the hazard results using the older EPRI-SOG models are not required but are useful to both the staff and applicant as an additional verification tool.

The staff reviewed NINA's software validation for all six of the original 1989 EPRI-SOG Teams' calculations and confirmed that there were differences between the original 1989 EPRI-SOG PSHA results and NINA's PSHA validation. While NINA was unable to match one of the original mean seismic hazard curves as well as some of the fractile seismic hazard curves, this was due to the lack of documentation in the original 1989 model rather than inadequacies in NINA's

PSHA software. Despite the inadequate documentation, NINA was able to match the majority of the original EPRI-SOG EST mean seismic hazard curves for the STP site. The staff considers the mean hazard curves the most relevant hazard comparison, as only the mean seismic hazard curves are used to develop the GMRS for the site. The details of the staff's evaluation are provided below.

As part of its validation, NINA was unable to match the original mean seismic hazard curve developed by Law Engineering, (one of the six EPRI-SOG ESTs), as well as some of the fractile seismic hazard curves. The mismatch stems from inadequate documentation in the original 1989 EPRI-SOG PSHA regarding the range of earthquake magnitudes that were included in the hazard assessments. Current guidance for PSHA calculations recommends including only those seismic sources that have magnitudes greater than or equal to 5.0. Therefore, NINA left seismic sources with maximum magnitudes less than 5.0 out of its PSHA validation. NINA explained that some of the Law Engineering Team's seismic sources surrounding and adjacent to the STP site had magnitudes lower than 5.0.

With respect to the mismatch in the 85th percentile fractile seismic hazard curve for the Dames and Moore Team, NINA explained that this result is due to the lack of seismicity and earthquake recurrence rates for some of this Team's seismic sources near the site. Available documentation did not discuss how the Dames and Moore Team's seismic sources without earthquake recurrence rates were treated in the original EPRI-SOG PSHA calculations. Consequently, NINA conservatively assigned nonzero recurrence rates to these seismic sources using half of the rate values from adjacent sources.

The staff reviewed NINA's assessment of the differences in the software validation results and found that NINA provided sufficient justification for the differences. Regardless of these differences, NINA was able to match five of the six original EPRI-SOG EST mean seismic hazard curves, which are the most relevant comparison, demonstrating that NINA's PSHA software is sufficient. In addition, as part of the NTTF 2.1 recommendations, the staff calculated seismic hazard curves and the GMRS for the STP site using the most recent seismic source models described in NUREG-2115. The staff's calculations showed that the COL GMRS calculated by NINA is overall slightly conservative compared to the GMRS calculated with the newer seismic source models. The staff concludes that NINA's PSHA software is adequate to run the PSHA calculations using the updated EPRI-SOG Earth Science Teams' models.

18. 10 C.F.R. § 100.23(d)(4) requires consideration of liquefaction potential of the STP site. Section 2.5S.4.8 of the FSAR presents NINA's evaluation of liquefaction potential at the STP site. In response to RAI 02.05.04-28 and as documented in Section 2.5S4.4.8 of the SER, NINA evaluated seismic-induced settlements for sandy soils using a procedure developed by Ishihara and Yoshimine (1992). NINA applied this method to soils with a factor of safety against liquefaction less than 1.4. According to Ishihara and Yoshimine (1992), seismic-induced volumetric strains are expected even when the factor of safety exceeds 1.4.

a. Why was volumetric strain evaluated for only soil layers with a factor of safety less than 1.4?

b. Would seismic-induced volumetric strains at the site be anticipated to propagate to the foundation elevation and affect the performance of safety related structures, systems, and components when considering soil layers having a factor of safety against liquefaction greater than 1.4?

c. **The method developed by Ishihara and Yoshimine (1992) for evaluating seismic-induced settlement is for free-field conditions (no structure being supported by the soil). What effect (if any) will structures have on estimated seismic compression?**

Staff Response:

a. The staff recognizes that some degree of volumetric strain is likely to occur under any given seismic conditions, and there is a strong correlation between volumetric strain and excess pore pressure ratio, or liquefaction potential. However, above a factor of safety (FS) of 1.4, those volumetric strains would be negligible.

The Regulatory Guide 1.198 (RG 1.198), *"Procedures and Criteria for Assessing Seismic Soil Liquefaction at Nuclear Power Plant Sites"* specifies that "soil elements with a high FS (FS >1.4) would suffer relatively minor cyclic pore pressure generation and should be assigned some large fraction of their (drained) static strength, obtained from laboratory tests, for further stability and deformation analysis." In other words, since minor cyclic pore pressures are expected when FS are greater than 1.4, liquefaction is considered unlikely and volumetric strains, if any, are expected to be negligible. Because of the uncertainties existing in soil properties and liquefaction potential evaluation procedures, an in-depth analysis, such as volumetric strain evaluation, is required to obtain more accurate liquefaction potential evaluation when FS is less than 1.4.

For the STP site, as stated in the response to RAI 2.5.4-28 and in the staff's final SER, volumetric strains were evaluated for soils with FS less than 1.4 and the staff concluded that liquefaction induced effects (settlement) are not likely to affect the behavior of foundations.

b. The seismic induced volumetric strain may or may not propagate to the foundation level depending on the soil saturation and cyclic force conditions. The induced volumetric strains, if any, would be negligible for soils with FS higher than 1.4 and therefore will not affect the performance of safety-related structures, systems and components.

c. The Ishihara and Yoshimine (1992) method, like other methods used in liquefaction analysis assumes free-field conditions. The heavy reactor structure built on the foundation will place a surcharge to the materials underneath, which will increase the confining stresses and density of the soil and thus, the strength of the soil and its ability to withstand ground motions. Using a method that assumes free-field conditions to estimate seismic-induced settlement without considering any surcharge is a more conservative approach.

19. 10 C.F.R. § 100.23(d)(4) requires consideration of the liquefaction potential of the STP site. In FSAR Section 2.5S.4.8.2.2, NINA describes the use of the "Chinese Method" to evaluate liquefaction potential of clayey soils. Peer-reviewed literature (e.g., Boulanger and Idriss 2004, Bray and Sancio 2004) states that the "Chinese Method" should no longer be used to evaluate liquefaction potential of clayey soils. In light of this peer-reviewed research, explain your conclusion that there is no liquefaction potential for the clayey strata at the STP site.

Staff Response: The staff recognizes that the "Chinese Method" was used to evaluate liquefaction potential of clayey soils for the STP site. The staff is also aware of the potential issues associated with the use of such a method. As stated in the final SER, the staff performed an independent liquefaction analysis to confirm the applicant's conclusions regarding liquefaction potential for the site. As part of this confirmatory analysis, the staff used both the RG 1.198 approach and recently developed alternative approaches to evaluate clayed soils. The confirmatory analysis results support the applicant's conclusions that the over-consolidated clay-type soils encountered at the site are not expected to liquefy.

20. Confirm that the actual thicknesses provided for the ultimate heat sink basin, the cooling tower enclosures, and the reactor service water pump house walls and slabs acting as missile barriers exceed the thicknesses calculated by both the National Defense Research Council formula, specified in NUREG–0800 Section 3.5.3, and the TM 5–855–1 formula, used by NINA, and are protective against penetration and perforation as well as scabbing. The SER text only discusses scabbing.

Staff Response: For site specific structures such as the ultimate heat sink basin, the cooling tower enclosures, and the reactor service water pump house walls and slabs, the applicant considered local damage evaluation in terms of penetration, perforation, and scabbing consistent with the formula in U.S. Army Technical Manual (TM) 5-855-1 referenced in ABWR DCD, Tier 2, Subsection 3.5.3.1.1, as described in STP Units 3 and 4 FSAR, Revision 12, Subsection 3H.11.1.

As part of the ABWR design certification review, the staff found that the use of the TM 5-855-1 equation resulted in sufficient concrete barrier thickness to prevent unacceptable penetration, perforation, and scabbing. To maintain consistency with the methodology of the DCD, the applicant chose to use the TM 5-855-1 equation. Because this equation was verified by impact tests and its use had previously been approved for the certified design, the staff found that confirmation of the results with the National Defense Research Council equation is not necessary.

The NRC staff considered penetration, perforation and scabbing in its review, but the SER discusses scabbing because it is the limiting case.

21. Regulatory Guide (RG) 1.206, § C.I.2.2.2.7 provides that the applicant should consider hazards from aircraft from nearby airports and aviation routes and § C.I.2.2.2.8 provides that the applicant should provide projections of the growth of these activities. Has a projection of aircraft traffic over the life of the facility been considered in the aircraft hazard evaluation? Discuss the results of that assessment.

Response to be submitted by the applicant only.

22. In performing the original site-specific soil structure interaction (SSI) and structure-soil-structure interaction (SSSI) analyses of embedded structures, NINA used the System for Analysis of Soil Structure Interaction (SASSI) Subtraction Method (SM) of analysis. In its letter to the Department of Energy dated April 8, 2011, the Defense Nuclear Facilities Safety Board identified a technical issue in SASSI that when the SM is used to analyze embedded structures, the results may be non- conservative. In RAI 03.07.01-29 the Staff requested that NINA demonstrate the acceptability of the SM and the results or to provide a plan and schedule to ensure that the structures, systems, and components (SSCs) are designed to meet General Design Criterion (GDC) 2 requirements. Describe the process followed to address the use of SM for site-specific SSI and SSSI analyses.

Staff Response: The SASSI code uses a detailed method referred to as the direct method (DM) and a simplified method referred to as the subtraction method (SM). The Defense Nuclear Facilities Safety Board (DNFSB) identified that the use of the SM could be non-conservative in certain situations compared to the analysis results obtained using the DM. To address this issue, the staff requested that the applicant demonstrate the acceptability of the SM results or to provide a plan to ensure that SSCs are designed to meet GDC 2 requirements.

The applicant performed extensive evaluation using the modified subtraction method (MSM) which was validated and verified against the DM. Where necessary, the seismic demand determined from the SM was modified to ensure that the STP Units 3 and 4 design is conservative. The staff performed audits to review STP's verification and validation program and determined that the STP site-specific MSM analyses were acceptable because the MSM analysis results were comparable to the results using the DM for benchmark structures representative of STP site conditions. Therefore, the staff concluded that the process followed to address the use of SM for the site-specific SSI and SSSI analyses is acceptable.

23. SER Section 3.7.2.4.19 discusses the Staff's assessment of a 10 C.F.R. Part 21 evaluation performed by Fluor Enterprises, Inc. By letter dated August 30, 2010, Fluor notified the NRC about an exceedance of the ABWR DCD seismic design input requirements for the main steam line seismic analysis of the turbine building for STP Units 3 and 4. Why was it not necessary for NINA to take a departure from the standard design in light of the exceedance addressed by Fluor?

Staff Response: The staff requested the applicant to address the exceedance of the ABWR DCD seismic design input requirements for the main steam line seismic analysis and revise the pertinent sections of the COLA.

The applicant responded that the ABWR DCD does not provide a detailed design or design analysis for the turbine building (TB). The applicant further stated that the detailed design of the STP Units 3 and 4 TBs is in progress. The design of the TB is not finalized and approved by the applicant. The applicant further stated the detailed design of the TB can be developed to be consistent with DCD Subsection 3.2.5.3. Fluor acknowledged that "applicants referencing the ABWR DCD may develop a range of turbine building design implementation details without departing from the requirements of the ABWR DCD."

In response to a staff request, the applicant also added new site-specific ITAAC in Part 9 of the COL application that specifically requires that a dynamic analysis of the TB will be performed to confirm that the DCD dynamic input requirements for the main steam line are satisfied for the final design of the TB. Based on the staff's review of the response and the addition of the site-specific ITAAC, the staff found that the applicant's response to address Fluor's Part 21 notice on the main steam line is acceptable, and determined that it is not necessary for NINA to take a departure from the standard design in this regard at this time.

24. SER Section 3.8.4.4.1 discusses the Staff's evaluation of lateral seismic earth pressures on below-grade external walls. The site-specific pressures for the Reactor Building and the Control Building exceed the corresponding pressures considered in the standard design.

a. What are the implications of such exceedance and the applicability of the standard design to the STP Units 3 and 4 site in this regard?

b. **Why was it not necessary for NINA to take a departure from the standard design for the site-specific lateral seismic earth pressures?**

<u>Staff Response</u>:

a. The site-specific local pressure exceedance required further evaluation of the below grade wall design for the Reactor Building and the Control Building. The applicant demonstrated that these exceedances would not impact the wall designs performed under DCD criteria because the induced out-of-plane shear and moment due to the localized exceedance on the walls are enveloped by the corresponding member forces considered in DCD design.

b. For the site-specific lateral seismic earth pressures, it is not necessary for NINA to take a departure from the ABWR standard design because the site specific lateral seismic earth pressures were considered as part of the departure from the site parameter for shear wave velocity. In addition, member forces in the walls induced by local exceedances of site-specific lateral pressure are bounded by the DCD values.

25. SER Section 3.8.4.4.5 discusses the Staff's evaluation related to site- specific departure STP DEP 3.5-2, "Hurricane Generated Missile Protection." This departure addresses the impact of new data and new guidance in RG 1.221, "Design-Basis Hurricane and Hurricane Missiles for Nuclear Power Plants" on the STP plant design. Based on this new data and guidance, some site-specific hurricane parameters exceed the tornado-based parameters used as the bounding wind design parameters in the ABWR standard plants. Discuss the implications of this exceedance for site-specific seismic Category I structures.

<u>Staff Response</u>: The site-specific seismic Category I structures consist of the ultimate heat sink (UHS)/reactor service water (RSW) pump house, the diesel generator fuel oil storage vault (DGFOSV), and the RSW piping tunnels. The applicant evaluated these structures under hurricane loading as specified in RG 1.221. With the exception of DGFOSV, the design of site-specific Category I structures can withstand the hurricane loading. For the DGFOSV, the hurricane missiles impacted the flexural and shear capacity of wall and roof panels. As a result, the applicant added additional shear reinforcement to the DGFOSV structure.

The staff reviewed the information provided in the COLA (including design modifications), responses to the requests for additional information, and conducted audits of the site-specific evaluation for the hurricane wind and hurricane missiles. The staff concluded that at the STP site, the design of the site-specific Category I structures is adequate to withstand the design-basis hurricane load specified in RG 1.221.

26. In SER Section 3.9.2.4.1, the Staff indicated that it questioned the applicability of the Kashiwazaki-Kariwa Plant (referred to as RJABWR in the SER) as a prototype plant for demonstrating the design of reactor internals against flow-induced vibration. However, the Staff evidently accepted the operating experience of the RJABWR steam dryer as evidence of safe design of the STP steam dryer (see, for example, first paragraph in Section 3.9.2.4.1.1.2). What were the reasons behind the Staff's initial skepticism of using the Japanese plant as a prototype? Why did the Staff ultimately conclude that the Japanese plant was an appropriate prototype?

Staff Response: Detailed information regarding the design, manufacture, qualification, installation, monitoring, inspection, and quality assurance of components installed in nuclear power plants in other countries is not as readily available to the NRC staff as similar information for the U.S. fleet. As a result, Regulatory Guide (RG) 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals during Preoperational and Initial Startup Testing," states that if the reactor-internals prototype testing is conducted on a reactor outside the United States, the detailed results of the testing should be included in any application related to a "non-prototype" component that is submitted to the NRC for review.

The applicant initially proposed the reactor internals in Kashiwazaki-Kariwa ABWR Nuclear Power Plant Unit 6 (RJABWR) in Japan to be the prototype for the reactor internals in STP Units 3 and 4. The staff, however, could not confirm the direct applicability of the RJABWR test results to STP Units 3 and 4 without additional information as outlined in RG 1.20. Therefore, the applicant revised the application to classify the reactor internals in STP Unit 3 as the prototype, with STP Unit 4 classified as a non-prototype, Category I, in accordance with RG 1.20. The applicant proposed that the Unit 4 steam dryer instrumentation plan and power-ascension license condition be identical to those for Unit 3. The applicant's proposal was acceptable to the staff.

As the staff summarized in Section 3.9.2.4.1.1.2, "Operating Experience," in the STP Units 3 and 4 COL final SER, the applicant provided the design and operating parameters of the STP Units 3 and 4 steam dryers in comparison to two ABWRs operating in Japan: the RJABWR reactor and the Japanese ABWR (JABWR) reactor. The STP Units 3 and 4 steam dryers are identical in geometry (configuration) and plant operating parameters to the RJABWR and JABWR steam dryers. The RJABWR started commercial operation in 1996, whereas the JABWR started in January 2005. These steam dryers in Japan have had routine visual inspections after removal during refueling outages, with no evidence of service-induced degradation. In addition, the RJABWR steam dryer received an inspection following an earthquake in 2007. Also, the JABWR steam dryer underwent an inspection after 5 years of operation in 2010. The staff reviewed the operating experience of the ABWR steam dryers and determined that because the steam dryers of STP Units 3 and 4 are identical in design and operating conditions to those in service in the RJABWR and JABWR, the operating experience from those steam dryers helps to inform the staff's finding regarding the expected structural performance of the STP Units 3 and 4 steam dryers.

To reach its conclusion regarding the acceptability of the STP Units 3 and 4 steam dryer design methodology and power ascension program, the staff relied on a combination of (1) the successful operating and inspection experience of the ABWR steam dryers in Japan that are identical to the STP Units 3 and 4 steam dryers, (2) limited diagnostic data obtained from the instrumented steam dryer in the RJABWR in Japan, (3) results of scale model testing conducted by the applicant for the STP Units 3 and 4 steam dryers, (4) redesign of the STP Units 3 and 4 steam system to reduce steam dryer stress below that experienced by the instrumented RJABWR steam dryer in Japan from acoustic resonance, (5) STP Units 3 and 4 steam dryer instrumentation provisions to monitor steam dryer performance during power ascension consistent with RG 1.20, and (6) a power ascension plan similar to the plans used for the successful startup of BWR nuclear power plants in the United States following extended power uprate license amendments.

27. What edition(s) of ASTM E-185, and the ASTM standards referenced therein, will be used to demonstrate compliance with Appendix H requirements?

<u>Staff Response</u>: As required by 10 CFR Part 50, Appendix H, the 1982 Edition of ASTM Standard E 185 (ASTM E 185-82) was used as the basis for the development of the applicant's surveillance program.

28. Did the Staff review the technical report, "Reactor Pressure Vessel Material Surveillance Program," Toshiba Corp., Apr. 2009 (UTLR-0003, Rev. 0), referenced in section 5.3.5 of FSAR, Rev. 12, to determine if NINA's surveillance program complies with Appendix H and ASTM requirements referenced therein? If so, what did the Staff conclude?

<u>Staff Response</u>: Yes. As stated in final SER Section 5.3.1.4, Technical Report UTLR-0003 was reviewed by the staff. The staff found that, in addition to information regarding the surveillance capsule program already provided in the FSAR (e.g., implementation milestones), Technical Report UTLR-0003: (a) provided the detailed locations of the surveillance capsules in the core beltline region, (b) described in detail the process for preparing the capsule specimens, and (c) specified the number and type of specimen in each capsule. The staff concluded that the applicant's surveillance program complies with ASTM E 185-82 and 10 CFR Part 50, Appendix H.

29. Did the Staff evaluate the dosimetry measurement criteria proposed in the combined license application that are based solely on measurements taken from dosimeters located outside of the reactor vessel surveillance capsules? If so, discuss the review, in view of ASTM E-185-82. That standard requires that a full set of neutron dosimeters be included inside of the surveillance capsules and performance of dosimetry measurements of these dosimeters when the capsules are removed in accordance with the reactor vessel surveillance capsule withdrawal schedule.

<u>Staff Response</u>: The dosimetry measurement program is not based solely on measurements taken from dosimeters located outside of the reactor vessel surveillance capsules.

ASTM E 185-82, Section 7.3.1 requires that neutron dosimeters be included in every reactor vessel surveillance capsule, and the applicant's program description (in the FSAR and Technical Report UTLR-0003, Rev. 0) indicates that neutron dosimeters will be provided in every capsule as required by ASTM E 185-82.

In addition, as allowed by ASTM E 185-82, Section 7.3.3, the applicant's program description (in the FSAR and Technical Report UTLR-0003, Rev. 0) indicates that additional, supplemental dosimetry will also be used to take neutron fluence measurements at the vessel inside diameter (outside of the reactor vessel surveillance capsules) in order to verify predicted neutron fluence calculations.

30. The application describes a single reactor vessel surveillance program for two units based on a four-capsule withdrawal schedule. Will NINA remove surveillance capsules for each unit or from only a single unit? If NINA intends to remove capsules from a single unit, did NINA receive Staff approval for an integrated reactor vessel surveillance program?

<u>Staff Response</u>: The applicant's proposed surveillance program is not an integrated surveillance program as described in 10 CFR Part 50, Appendix H, Section III.C. Although the program document addressed both units, each reactor vessel will have its own surveillance program and the applicant will remove four surveillance capsules from each unit.

31. How has NINA demonstrated compliance with the upper-shelf energy requirements for ferritic reactor pressure vessel beltline components and welds in: (a) the procured, pre-service, unirradiated condition to ensure the materials have a Charpy upper-shelf energy of at least 75 ft-lb, and (b) the irradiated condition to ensure that the materials will have a Charpy upper-shelf energy of at least 50 ft-lb throughout the licensed operating periods for the reactors?

<u>Staff Response</u>: To demonstrate compliance with the fracture toughness requirements of 10 CFR Part 50, Appendix G, Section IV for the reactor vessel materials in the as procured, pre-service, unirradiated condition, the applicant provided the following commitment in the FSAR:

> Fracture toughness data based on the limiting reactor vessel actual materials will be provided in an amendment to the FSAR in accordance with 10 CFR 50.71(e) that occurs one year after the on-site acceptance of the reactor vessel. The data will be based on test results from the actual materials used in the RPV. (COM 5.3-1)

The applicant does not yet have the as-procured data.

The applicant's reactor vessel surveillance program will be used to monitor changes in the fracture toughness properties of ferritic material in the reactor vessel resulting from exposure to neutron irradiation and the thermal environment. The applicant's reactor vessel surveillance program meets the requirements of 10 CFR Part 50, Appendix H, which provides reasonable assurance that fracture toughness requirements, which include upper shelf energy, will be met throughout the operating life of the reactor vessel.

If at any time, the licensee predicts that the Charpy upper-shelf energy will fall below 50 ft-lb, then 10 CFR Part 50, Appendix G requires that the licensee demonstrate that lower upper-shelf energy values will provide adequate margins of safety. This analysis must be submitted at least three years prior to the date when the predicted upper-shelf energy will no longer satisfy the requirements.

32. The Final Safety Evaluation Report Related to the Certification of the Advanced Boiling Water Reactor Design, NUREG-1503, (July 1994), Section 5.2.1.1 states: "[A]ll ASME Code, Class 1, 2, and 3 pressure- retaining components and their supports shall be designed in accordance with the requirements of ASME Code, Section III, using the specific edition and addenda given in the [ABWR Standard Safety Analysis Report]. The [combined license] applicant should ensure that the design is consistent with the construction practices (including inspection and examination methods) of the ASME Code edition and addenda in effect at the time of [the combined license] application, as endorsed in 10 CFR 50.55a. The . . . applicant should identify in its application the portions of the later code editions and addenda for NRC staff review and approval. The portions of the later Code editions and addenda must be identified to the NRC staff for review and approval with the COL application. This was DFSER COL Action Item 14.1.3.3.2.1-1."

For NINA: How and where does the application address COL Action Item 14.1.3.3.2.1-1? In addition, does the combined license application have any design departures that require ASME Section III relief requests under 10 C.F.R. § 50.55a

that require Staff approval before issuance of a combined license?

For the Staff: How and where does the SER evaluate NINA's response to COL Action Item 14.1.3.3.2.1-1?

Staff Response: Components (including piping) and their supports for STP Units 3 and 4 are designed in accordance with ASME Boiler and Pressure Vessel Code (BPV Code), Section III, Division 1, 1989 edition with no addenda, as specified in STP Units 3 and 4 FSAR Table 1.8-21, "Industrial Codes and Standards Applicable to ABWR." This is the same code referenced in the ABWR design certification. It is also one of several editions incorporated by reference (with conditions) in 10 CFR 50.55a, both currently and at the time of the submission of the COL application.

STP Units 3 and 4 COL final SER Section 3.9.3, "ASME Code Class 1, 2, and 3 Components, Component Supports, and Core Support Structures," and Section 5.2.1.1, "Compliance with 10 CFR Part 50, Section 50.55 [Related to RG 1.206, Section 5.2.1.1, 'Compliance with 10 CFR 50.55a'],'' contain the staff's evaluation of this information.

Draft final SER (DFSER) Action Item 14.1.3.3.2.1-1 addresses the same issue later identified as COL License Information Item 3.30. This item is listed in ABWR Site Safety Analysis Report (SSAR) / Design Control Document (DCD) Table 1.9-1, "Summary of ABWR Standard Plant COL License Information," and described in SSAR/DCD Section 3.9.7.4, "Audit of Design Specification and Design Reports." COL License Information Item 3.30 includes actions for COL applicants to (1) make ASME design specifications and design reports available for audit, (2) ensure that the piping system design is consistent with construction practices of the ASME Code edition and addenda as endorsed in 10 CFR 50.55a in effect at the time of application, and (3) identify for NRC review and approval the use of any ASME Code editions and addenda other than those listed in SSAR Tables 1.8-21 and 3.2-3.

DFSER Action Item 14.1.3.3.2.1-1 and COL License Information Item 3.30 are linked together through ABWR final SER Section 14.1, "Preliminary Safety Analysis Reports Information," which indicates that the discussion of piping was moved to Section 3.12 of the final SER. ABWR final SER Section 3.12.2.1, "ASME Boiler and Pressure Vessel Code," also refers to DFSER Action Item 14.1.3.3.2.1-1 and includes the same statement referenced in the Commission's question from ABWR final SER Section 5.2.1.1, "Compliance With 10 CFR 50.55a." ABWR final SER Section 3.12.2.1 includes the additional insight that "GE has included this action in SSAR Section 3.9.7.4, which is acceptable." In addition, ABWR final SER Section 5.2.1.1 provides further background on the staff's intent related to ASME Code editions—essentially, that COL applicants must use the ASME Code editions referenced in the SSAR/DCD unless justified by the applicant and approved by the NRC.

As discussed in STP Units 3 and 4 COL FSER Section 3.9.3, the applicant included a site-specific supplement to address COL License Information Item 3.30 in Subsection 3.9.7.4 of the STP Units 3 and 4 final SAR. This supplement stated that (1) design specifications and reports would be made available for audit, (2) the piping system design is consistent with construction practices of the ASME Code 1989 edition, and (3) no additional ASME Code editions and addenda other than those listed in DCD Tier 2, Tables 1.8-21 and 3.2-3 will be used. The staff evaluated this information in STP Units 3 and 4 COL final SER Section 3.9.3 and found it acceptable. This final SER section also describes the audit conducted by the staff of the referenced design specifications.

Additional evaluation of this topic is included in STP Units 3 and 4 COL final SER Section 5.2.1.1, in which it states that the staff confirmed that the information in the application and the information incorporated by reference address the relevant information related to codes and standards. The staff again referred in this final SER section to ABWR DCD Tier 2, Table 1.8-21. The staff found the information submitted by the applicant acceptable to resolve COL License Information Item 3.30.

In summary, as discussed in STP Units 3 and 4 COL final SER Sections 3.9.3 and 5.2.1.1, the staff reviewed the applicant's use of ASME Code editions and addenda (i.e., the 1989 edition with no addenda) as required by the ABWR DCD and found it to be acceptable, resolving COL License Information Item 3.30, which addresses the issue previously referred to as DFSER COL Action Item 14.1.3.3.2-1.

33. The Containment Overpressure Protection System (COPS) opens to vent the containment when the wetwell pressure is 0.72 megapascals, which is significantly below the estimated failure pressure of the drywell head. The Fukushima event showed that hydrogen can leak into the secondary containment and lead to explosions.

a. Is the COPS opening pressure low enough to prevent significant hydrogen leakage into the secondary containment?

b. Does the protection provided by the ABWR COPS meet the requirements for hardened vents in Mark I or Mark II containments required by Order EA-13-109?

<u>Staff Response</u>:

a. Yes, as stated in ABWR DCD Rev. 4 Section 19.2.4.3, "Containment Analysis and Key Results," the design certification applicant's evaluation showed no significant leakage from containment below the COPS opening pressure of 0.72 MPa. The staff found this acceptable in the ABWR certification.

b. For the reasons set forth in response to Question 56, the staff did not specifically evaluate STP Units 3 and 4 with respect to compliance with Order EA-13-109 because the STP units do not have a Mark I or Mark II containment. The ABWR design would be considered under NTTF recommendation 5.2, a Tier 3 Fukushima action item. However, the COPS is a hardened vent system consisting of two over pressure relief rupture disks that relieves pressure from the top of the suppression pool air space to the atmosphere via the plant stack. This system is intended to provide protection against the rare sequences in which structural integrity of the containment is challenged by over pressurization.

34. In FSAR Section 6C.1, NINA committed to following the guidance in RG 1.82, Rev. 3, "Water Sources for Long-Term Recirculation Following a Loss-of-coolant Accident." Since the STP application was submitted, new guidance has become available regarding the long-term cooling regulated under 10 C.F.R. § 50.46(b)(5), which is described in RG 1.82, Rev. 4. Did the Staff consider the newly-identified issues in Revision 4 of RG 1.82 when reviewing the application (i.e., vortexing, flashing, deaeration, and chemical effects)? If so, provide details on how NINA addressed the safety considerations available in the updated guidance. If not, explain why NINA's approach meets 10 C.F.R § 50.46(b)(5).

<u>Staff Response</u>: The STP application was tendered September 20, 2007. Regulatory Guide 1.82, Revision 3, dated November 2003, was in effect 6 months prior to the submittal of the STP application, and was the applicable guidance at that time. Regulatory guides offer one means of demonstrating compliance with NRC requirements; whereas, the staff's finding is on meeting the regulations and not a particular regulatory guide. Revision 4 of Regulatory Guide 1.82 was issued in March 2012 and offered enhanced guidance for licensees and applicants on issues such as vortexing, flashing, deaeration, and chemical effects.

While the regulatory guide was updated in 2012, the staff was aware of the potential design concerns associated with vortexing, flashing, deaeration, and chemical effects at the time of the review of the STP application as these concerns relate to net positive suction head (NPSH). This led to consideration of these effects in the staff's review of 10 CFR 50.46(b)(5), including pump NPSH. The staff issued requests for additional information on the strainer design and NPSH evaluations and conducted a regulatory audit to review the applicant's calculations. The audit was documented in audit summaries dated October 21, 2009 (ML092670380) and December 22, 2010 (ML103480636).

As discussed in the staff's final SER in sections 5.4.7, "Residual Heat Removal System," and 6.2.1, "Containment Functional Design," the applicant was requested to provide the calculations of pump NPSH for the residual heat removal (RHR), reactor core isolation cooling (RCIC), and high pressure core flooder (HPCF) systems. These calculations were reviewed in an audit, and demonstrated substantial margin to the minimum NPSH required. As a result, the staff concluded that the design met 10 CFR 50.46(b)(5).

See also the staff's response to Question 35 for related information on the consideration of chemical effects.

35. In FSAR Section 6C.3.1.9.3, NINA applies an NRC-approved topical report, WCAP-16530-NP-A, "Evaluation of Post-Accident Chemical Effects in Containment Sump Fluids to Support GSI-191," (available at ADAMS accession number ML081150383) when evaluating chemical effects on long-term recirculation cooling following a loss of coolant accident. However, WCAP-16530-NP-A is specific to pressurized water reactor designs. Boiling water reactors have post-loss-of-coolant accident containment conditions that may result in different chemical interactions than those analyzed in WCAP-16530-NP-A. Discuss how the application of pressurized water reactor guidance to a boiling water reactor design is adequate to meet the long-term core cooling requirements of 10 C.F.R. § 50.46(b)(5).

<u>Staff Response</u>: WCAP-16530-NP-A was developed and approved for a range of materials, temperature, post-loss-of-coolant accident (LOCA) pool and spray pH, and pH buffer chemicals representing the pressurized water reactor (PWR) fleet. Boiling water reactors (BWRs) generally use the same range of structural and insulation materials as PWRs. Although developed for PWRs, the WCAP-16530-NP-A methodology is based on testing and analysis of materials proposed for STP Units 3 and 4, and this testing and analysis cover temperature and pH ranges that bound the postulated post-LOCA conditions for STP Units 3 and 4. This similarity of materials and environments, and conservative applicant assumptions regarding the debris source term and precipitation for key materials, are the reason the staff generally accepted the use of WCAP-16530-NP-A in the chemical effects analysis for review.

The staff did not make a finding that WCAP-16530-NP-A is generically applicable to BWR designs. In reviewing the STP application, the staff found portions of the topical report applicable to the STP application when supplemented by STP specific considerations such as the debris source term and chemical precipitate formation.

In summary, the staff found the use of the WCAP-16530-NP-A methodology to provide a conservative chemical debris analysis because the applicant will limit the use of materials found to contribute to chemical effects in PWR environments, and conservative assumptions were used to address STP specific conditions.

36. FSAR Section 6C.5, which provides the Strainer Sizing Analysis Summary, states: "Debris on the screen creates a pressure drop as predicted by NUREG/CR-6224 and NUREG/CR-6808 which is referenced by Regulatory Guide (RG) 1.82. Pressure drop caused by the mixed particulates and fiber bed is calculated by the equation shown on NUREG/CR-6224 Appendix B."

RG 1.82, Rev. 4 states: "In future evaluations, BWR [boiling water reactor] strainer designs should consider subsequent guidance developed during the resolution of GSI-191 and GL 2004-02 including chemical and downstream effects and strainer head loss and vortexing." The NUREG/CR-6224 correlation was primarily developed for application to flat screens and plates, but the Advisory Committee on Reactor Safeguards (ACRS) has questioned its application to flat screens and plates (*see* G. Wallis review of the NUREG/CR-6224 Head Loss Correlation, 8/20/2004 (available at ML042400166)). Comparisons between the NUREG/CR-6224 correlation predictions and test data for flat screens and plates showed that the correlation did not predict or bound measured data in many situations (*see* NUREG-1862; NUREG/CR-6917). Additionally, the correlations are not applicable to the complex geometries present in a strainer and may yield non-conservative results that may result in undersized strainers. Consequently, RG 1.82, Rev. 4 further states: "Licensees should validate the adequacy of ECCS [Emergency Core Cooling System] strainer designs through testing applicable to plant-specific conditions. Analytical or empirical head loss correlations should not be used to validate plant-specific debris bed head losses."

In view of these concerns, provide details of the plant-specific strainer tests that have been performed to validate the adequacy of the STP strainer design.

<u>Staff Response</u>: The staff based the acceptability of the strainer design on the fact that the head losses assumed by the applicant had sufficient margin with regard to net positive suction head (NPSH). This margin exists because the fiber loading on the strainers in STP Units 3 and 4 is very low (1 ft^3), to the point that minimal head losses over the strainers are expected. Nevertheless, in order to demonstrate that the head loss assumed across the strainers was conservative, the applicant referenced a series of laboratory tests on the STP strainer design. The STP Units 3 and 4 design does not use a flat plate strainer, and thus the testing was performed to obtain a shape factor for the cartridge-type strainers used by the design. The shape factor acts as a multiplier for the correlation contained in NUREG/CR-6224, and the applicant then increased the shape factor by 10 percent for conservatism. The applicant further referenced testing of a scaled strainer subjected to varying debris loadings, including a maximum total debris loading that is much higher than the fiber loading permitted at STP Units 3 and 4. These tests demonstrated that the analytically calculated head loss term was at least 15 percent higher than the head loss obtained via testing, due to conservatisms used in the correlation assumptions.

37. The Staff issued RAI 07.09-5 requesting that NINA provide sufficient information addressing a safety and hazards analysis, a sneak circuit analysis, and a timing analysis for the digital instrumentation and control (I&C) systems. In response to this RAI (STPNOC Letter U7-C-STP-NRC- 090157), NINA stated that the verification of the I&C system design and analysis will be accomplished during the ITAAC phase. In SER section 7.9S.4, the Staff found the related ITAAC acceptable, such that when the ITAAC is performed and the acceptance criteria are met the facility would have been constructed and will operate in conformance with the combined license and the NRC regulations.

The response to RAI 07.09-5 references the response to RAI 14.03.05- 04 that states: "The safety-related I&C systems are deterministic. The response times for the system elements, including architecture, communications (including timing and loading) and processing elements will be analyzed in accordance with BTP 7-21 to verify that the systems' performance characteristics are consistent with the safety requirements established in the design basis for these systems . . . . Regarding the request for additional ITAAC, STPNOC's position is that the existing ITAAC is appropriate as discussed in the response to RAI 14.03.05-8." The response to RAI 14.03.05-8 states, in turn: "The ITAAC that can be considered I&C related Design Acceptance Criteria (DAC) are provided in STP 3&4 COLA Part 2 Tier 1, Section 3.4 Table 3.4 Items 7-15. This is supported by the ABWR DCD Subsection 14.3.3.4 and NUREG- 1503 Section 14.3.3.4. As noted therein, the DAC provide the process and acceptance criteria by which the details of the I&C systems' design are developed, designed and evaluated."

The acceptance criterion listed in the ABWR DCD FSAR Tier 1, Section Table 3.4 Item 8.e states that the Software Management Plan shall define "[t]he Design Definition phase design activities, which shall address the development of the following implementing equipment design and configuration requirements . . . [d]ata communications protocol, including timing analysis and test methods . . . ."

a. Is this the only ITAAC that provides the timing analysis of the entire safety I&C system from sensor output to the final actuation device?

b. Is there an ITAAC that verifies that the as-built safety I&C system can complete the required safety functions (e.g., reactor trip and engineered safety features actuation system functions) in the required time assumed in the safety analysis?

<u>Staff Response</u>:

a. No. In addition to the acceptance criteria of Item No. 8.e(4) quoted in Question 37, STP Units 3 and 4 FSAR Table 7DS-1 specifies the following DAC/ITAAC for verification of the safety-related I&C System timing:

- Tier 1, Table 3.4, DAC/ITAAC No. 8.b
- Tier 1, Table 3.4, DAC/ITAAC No. 8.e
- Tier 1, Table 3.4, DAC/ITAAC No. 8.g
- Tier 1, Table 3.4, DAC/ITAAC No. 8.h

- Tier 1, Table 3.4, DAC/ITAAC No. 8.i
- Tier 1, Table 3.4, DAC/ITAAC No. 11

b. ABWR DCD Tier 2, Section 7.2.2.1, "Conformance to Design Bases Requirements," and Section 7.3.1.2, "Design Basis Information" (incorporated by reference in the STP Units 3 and 4 FSAR) refer to Chapter 15 for the timing of functions credited for the reactor protection system, engineered safety feature systems, and leak detection and isolation system. STP Units 3 and 4 FSAR, Section 7DS.2.3.2.2 states that the overall response time for an ESF safety function includes the delay time for each element in the processing chain from sensor to the component actuation and each step in the process is predictable and repeatable.

STP Units 3 and 4 FSAR Table 7DS-1 specifies the following ITAAC to verify that the as-built safety I&C system can complete the credited safety functions in the times specified in the safety analysis:

- Tier 1, Table 3.4, ITAAC No. 2
- Tier 1, Table 2.7.5, ITAAC No. 2

38. Branch Technical Position (BTP) 7-21 states, "Design basis documents should identify design practices that the applicant/licensee will use to avoid timing problems. Risky design practices such as non-deterministic data communications, non-deterministic computation, use of interrupts, multitasking, dynamic scheduling, and event-driven design should be avoided." The STP combined license application, Tier 2 Section 7DS.2.3.2.2 states that "The timing analysis is performed as required by the NRC in the Plant Specific Action Items described in the Safety Evaluation report for the Common Q Topical Report, WCAP-16097-P-A. This topical report provides additional information on the deterministic performance of safety systems based on use of the Common Q platform." Per the guidance of BTP 7-21, use of multitasking designs should be avoided in order to meet performance and timing requirements. However, the NRC Staff has approved platforms (e.g., Common Q) that employ multitasking provided certain limitations are enforced (e.g., Central Processing Unit loading limitations). In the case of the Common Q platform, WCAP-16097-P-A states that as long as the Central Processing Unit load is less than 70 percent, then the application program will operate deterministically.

Since the Engineered Safety Features Logic and Control System will be developed using the Common Q platform, is there an ITAAC to verify that the as-built system will meet the 70 percent Central Processing Unit load restriction?

Staff Response: Yes, there are ITAAC to verify the as-built I&C systems using the Common Q platform meet the 70 percent Central Processing Unit (CPU) load restriction. STP Units 3 and 4 FSAR Section 7DS.2.3.2.2, "ELCS Controller Processing," states, "The timing analysis is performed as required by the NRC in the Plant Specific Action Items described in the Safety Evaluation report for the Common Q Topical Report, WCAP-16097-P-A. This topical report provides additional information on the deterministic performance [including the 70 percent CPU load restriction] of safety systems based on use of the Common Q platform."

The STP Units 3 and 4 FSAR describes formal timing analysis and validation testing that demonstrates that all ESF safety functions are deterministic and are designed to function as credited in the Chapter 15 Safety Analysis. Specifically, STP Units 3 and 4 FSAR Section 7DS.2.3, "Determinism," and Table 7DS-1, "Cross Reference of the Tier 1 DAC/ITAAC Required for DI&C Verification" refer to:

- Tier 1, Table 3.4, ITAAC No. 2
- Tier 1, Table 3.4, DAC/ITAAC No. 8b
- Tier 1, Table 3.4, DAC/ITAAC No. 8e
- Tier 1, Table 3.4, DAC/ITAAC No. 8h
- Tier 1, Table 3.4, DAC/ITAAC No. 8i
- Tier 1, Table 3.4, DAC/ITAAC No. 11
- Tier1, Table 2.7.5, ITAAC No. 2.

39. How does the application address the issue of spurious actuations induced by means other than heat or fire, such as instrumentation and control (I&C) system failures (e.g., control system or safety I&C system common cause failures)? This issue is of special concern when these active failures may lead to transients that are not analyzed in the safety analysis.

<u>Staff Response</u>: The certified ABWR design included the design and analysis for spurious actuations caused by I&C system failures, which is incorporated by reference in STP Units 3 and 4 FSAR, Chapter 7, without departures. Accordingly, this matter is resolved for this COL proceeding in accordance with 10 CFR 52.63(a)(5). As discussed below, the ABWR DCD, Chapter 7, in general states that the setpoints, power sources, and instrumentation and controls are arranged in such a manner as to preclude spurious scrams and actuations insofar as practicable and safe.

ABWR DCD Tier 2, Section 7.7.2, "Analysis," includes or references analysis that demonstrates that the plant protection systems are capable of coping with any postulated failure mode of the control systems. Expected or abnormal transients due to spurious failures in control systems are the limiting events and are bounded by the safety analysis in ABWR DCD Chapter 15. Fundamentally, reactor vessel instrumentation must perform its safety functions in the event of any plant transient. ABWR DCD Tier 2, Section 7.7.2.1.1 states that none of the nonsafety-related ABWR reactor vessel instrumentation is required to initiate or control any engineered safeguard or safety-related system function.

As described in the ABWR DCD Tier 2, Section 7C.5, "Details of Final Implementation of Diversity in ABWR Protection System," to maintain protection system defense-in-depth in the presence of a postulated worst-case event (i.e., undetected, 4-division common mode failure of all communications or logic processing functions in conjunction with a large break LOCA), diversity is provided in the form of a hardwired backup of reactor trip instrumentation, a diverse display of important process parameters, defense-in-depth arrangement of equipment, and other equipment diversity.

40. In FSAR Subsection 8.3.1.1.4.1, NINA discusses the design of the 120 VAC Class 1E instrument power system and provides the following information:

> **Individual regulating transformers supply 120 VAC to the four divisions of instrument power (Figure 8.3-2). Each Class 1E divisional transformer is supplied from a 480V MCC in the same division, except for the Division IV transformer, which is supplied from the 480V MCC of Division II. There are three divisions (I, II, and III), each backed up by its associated divisional diesel generator as the source when offsite source is lost. Division IV is backed up by the Division II diesel generator, when the offsite source is lost. Power is distributed to the individual loads from distribution panels, and to logic level circuits through the control room logic panels. Transformers are sized to supply their respective distribution panel instrumentation and control loads.**

Departure STD DEP T1 2.12-2, I&C Power Divisions, provides for a fourth instrument power division as opposed to the three divisions in the ABWR certified design. The fourth division is not a separate entity from the original three. The fourth is also powered by Division II. Whenever two redundant and independent entities are powered from the same division, the concern arises as to the possibility of common cause failure of both entities. Discuss how the Staff's single failure analysis for this aspect of the design took into account potential common cause mechanisms.

Staff Response: The applicant's electrical design relies on three independent divisions of the Class 1E power system to provide power to four I&C channels, as stated in FSAR Section 8.3.1. Specifically, each of the three Class 1E safety buses can be supplied by offsite power through the unit auxiliary transformers or reserve auxiliary transformers. Onsite power for each Class 1E division is available from a Class 1E diesel generator or a Class 1E battery. In the event of a single failure in Division II of the Class 1E power system, the Class 1E batteries will supply power to I&C channels II and IV for at least two hours. Accordingly, the loss of the Division II Class 1E diesel generator does not result in the loss of power to I&C channels II and IV for at least two hours, which will allow for an orderly shutdown of the affected unit or restoration of onsite or offsite power (the loss of two I&C channels would otherwise result in a reactor trip). As explained below, a single failure in any Class 1E electrical power division will not affect the other two divisions. Hence, at least two divisions of Class 1E instrument power remain available in the event of a single failure.

Each independent division of Class 1E power has interrupting devices, *i.e.*, circuit breakers, to isolate faults, as shown in FSAR Figure 8.3-2. ITAAC Item 9 in Table 2.12.15 of DCD Tier 1 states that "Class 1E Instrument and Control Power Supply system interrupting devices (circuit breakers and fuses) are coordinated to the maximum extent possible, so that the circuit interrupter closest [to] the fault opens before other devices." Analyses will confirm that the interrupting device closest to the fault will actuate first in the event of a fault. This ITAAC ensures that interrupting devices are coordinated such that a fault in Division II will be isolated and I&C channels I and III are unaffected and able to perform their safety function.

Separation and electrical isolation of the three divisions of Class 1E power ensure that no one design basis event is capable of disabling more than one division, in accordance with GDC 17 and RG 1.75, "Physical Independence of Electric Systems." ABWR DCD Section 8.3.3.1 describes the physical separation and independence features of the design, and shows that

Class 1E electrical equipment is located to provide separation and electrical isolation among the divisions. This ensures that Class 1E power will be available from at least two electrical power divisions in the event of a single failure in one division.

Thus, three independent and redundant divisions of Class 1E power ensure that the I&C divisions have power adequate to perform their safety functions.

41. SER Section 9.1.1.4 (COL License Information Item 9.5) states that NINA provided a new diagram to demonstrate that the new fuel inspection platform would meet safe shutdown earthquake (SSE) criteria. Does this piece of equipment meet the criteria to be classified as Seismic Category 1, and if so, how did the Staff verify that the equipment would perform its intended function during a SSE event?

<u>Staff Response</u>: The new fuel inspection stand provides support for the new fuel bundles that are being inspected and a working platform for a plant worker who performs the inspection. It serves no safety-related function and is not classified as seismic Category I equipment. This classification is consistent with ABWR DCD Table 3.2-1, "Classification Summary," which the applicant incorporates by reference in FSAR Section 3.2.

To verify that the new fuel inspection stand would perform its intended function during an SSE event, the staff requested that the applicant describe the design of the new fuel inspection stand. The applicant provided a revised figure in the FSAR which demonstrated that the new-fuel inspection stand is anchored into the floor of the new fuel inspection pit and the refueling floor so that it cannot fall or tip, and will retain the fuel assembly and maintain the structural integrity of the stand during an SSE. The staff verified that the new fuel inspection platform design ensured that during an SSE event, the inspection stand will not fall or drop personnel into the spent fuel pool. Therefore, the staff agreed that the proposed design will meet SSE criteria and satisfy its intended function.

42. How has the Staff evaluated that, in the event of a fire in the digital instrumentation and control panels located in the Control Room Complex, operators can identify the loss of control due to fire-induced spurious actuations and initiate transfer to the remote shutdown panel prior to the plant experiencing unrecoverable conditions?

<u>Staff Response</u>: NRC requirements and guidance related to the transfer to the remote shutdown panel identify the need for the remote shutdown panels to be physically and electrically independent of the control room complex. Also, at least one of the areas must remain habitable. Therefore, a fire in either area will not affect shutdown capability in the other area. The operators' required training and knowledge in conjunction with indicating alarms, indicating lamps, and the availability of control room procedures, provide the NRC staff with reasonable assurance that operators would be able to assess and identify a loss of control event and to actuate the transfer prior to experiencing unrecoverable conditions.

43. How are fire-induced shorts to ground on ungrounded systems evaluated to ensure that safe shutdown functions are not impeded by spurious operation(s) caused by ground fault equivalent hot shorts?

<u>Staff Response</u>: There is no specific guidance for ground fault equivalent hot shorts at this time. The staff and the industry are currently conducting testing and research on this recently discovered hot short scenario to determine its significance and the required regulatory response, if any.

With regard to fire-induced spurious actuation(s), the applicant for STP Units 3 and 4 has committed to the NRC-endorsed guidance, NEI 00-01, Revision 2, “Guidance for Post-Fire Safe Shutdown Circuit Analysis.” The post-fire electrical circuit analysis by STP Units 3 and 4 will be completed as part of the detailed design of the circuits and cable layouts. By committing to the endorsed circuit analysis methodology of NEI 00-01, Revision 2, and RG 1.189, Revision 2 (spurious actuation sections), the staff concludes that there is reasonable assurance that the analysis will be adequately performed in accordance with 10 CFR 50.48, “Fire Protection,” and General Design Criteria 3, “Fire Protection.”

44. Please clarify how NINA’s combined license application, Revision 12 (Attachment 3 to the NINA letter dated April 21, 2015 (ML15124A267)) addresses the ACRS’s concern expressed in its February 19, 2015, letter to Chairman Burns (ML15039A006) with respect to the turbine control and protection system. The ACRS stated:

> **The final plant-specific turbine missile analyses should explicitly evaluate each turbine control and protection system including the turbine speed sensors, all component failure modes, all required support systems and the measured material toughness properties for the STP Units 3 and 4 monoblock rotors.**

Is the Staff’s safety determination based upon this updated commitment from NINA, and if so, what obligation is placed on the licensee to fulfill the commitment as stated?

<u>**Staff Response**</u>**:** The basis for the Staff’s safety determination regarding protection from turbine missiles is the license condition imposed on the applicant which states:

> The licensee shall, as part of their turbine maintenance program, perform the following:
>
> - volumetrically inspect all low-pressure turbine rotors at the second refueling outage and every other (alternate) refueling outage thereafter, and
> - test, at least once a week during normal operation, the main steam control and stop valves, intermediate intercept and stop valves, and steam extraction nonreturn valves.

This license condition is consistent with Standard Review Plan Subsection 3.5.1.3 and is imposed when the applicant has not provided an NRC-approved turbine missile probability analysis as the basis for a turbine system maintenance program. The staff finds the inspection and testing requirements imposed by this license condition to be adequate with respect to ensuring adequate protection from turbine missiles.

A turbine missile probability analysis may form the basis for refining the inspection and testing frequencies that will be specified in the turbine maintenance program. For example, typical turbine missile probability analyses refine the inspection frequency of the turbine rotor to 10 year intervals. When the applicant provides a turbine missile probability analysis for NRC review and approval, it can seek to have the license condition removed. The updated commitment (COM 3.5-1) from the applicant states:

> A turbine system maintenance program will be submitted within three years following receipt of a COL that includes a probability calculation of turbine missile generation and shows that the turbine meets the minimum requirements as given in Table 3.5-1. This probability calculation shall evaluate each turbine control and protection system (for example, the condition that the primary overspeed trip system may be out of service during turbine operation) and all component failure modes to calculate the probability of turbine missile generation.

This commitment documents specific considerations which will be incorporated into any future turbine missile probability analysis that the applicant submits for staff review.

Finally, concerning the material toughness properties of the turbine rotor, FSAR Section 10.2.5.1 notes licensee commitment COM 10.2-1, which states:

> In accordance with 10 CFR 50.71(e), STPNOC will update the FSAR to identify the as built turbine material property data that supports the material properties used in the turbine rotor design specified in Subsection 10.2.3.2, after procurement and prior to initial fuel load.

Thus, the applicant will provide the material properties of the turbine rotor, which will be used in the turbine missile probability analysis. As stated previously, this analysis would be reviewed by the staff as part of a future license amendment request to remove the license condition requiring conservative inspection and testing frequencies for turbine maintenance.

Therefore, licensee commitments COM 3.5-1 and COM 10.2-1 address the issues raised by the ACRS.

45. 10 C.F.R. § 20.1601(d) requires that the licensee establish controls in a way that does not prevent individuals from leaving a high or very high radiation area. Therefore, a door to a high or very high radiation area must be designed in a way that would allow an individual inadvertently locked inside such an area, to leave the area.

How are the 10 C.F.R. §§ 20.1601 and 20.1602 requirements met for radiation protection doors in containment?

Staff Response: The design of radiation protection doors was addressed in the ABWR DCD.

Section 3.8.2.1.1.1 “Personnel Air Locks” of the ABWR DCD specifies that there are two personnel air locks, each with two doors that can be operated from either inside or outside the containment vessel. In addition, the applicant commits to NEI 07-03A, “Generic FSAR Template Guidance for Radiation Protection Program Description,” in FSAR Section 12.5,

“Operational Radiation Protection Program,” which specifies that procedures for access control will assure compliance with 10 CFR 20.1601 and 10 CFR 20.1602 and are consistent with the guidance in Regulatory Guide 8.38, “Control of Access to High and Very High Radiation Areas of Nuclear Power Plants.” Regulatory Guide 8.38 specifies that controls must be established to prevent personnel from being locked in a high radiation area and indicates that if chains and padlocks are used to lock high radiation areas, procedural controls must prevent the area from being locked with personnel inside. In addition, Regulatory Guide 8.38 specifies that if doors are self-locking, personnel must be able to open them from the inside without a key.

Therefore, the personnel air lock door design in the DCD, along with the applicant's commitment to NEI 07-03A and Regulatory Guide 8.38 ensure that the requirements of 10 CFR 20.1601(d) and 10 CFR 20.1602 for ensuring individuals do not get locked inside high or very high radiation areas, will be met.

46. The FSAR provides that a Plant Operations Review Committee (PORC) will be established to advise the plant General Manager on all matters related to nuclear safety at STP Units 3 & 4. When does the PORC begin—upon issuance of the combined license, at fuel load, or at some other time?

Response to be submitted by the applicant only.

47. The application (FSAR, page 13.1-10) provides: "Toshiba will have overall responsibility for design and configuration control." Will the licensee have access to all design documents (including proprietary documents) for the life of the plant?

Response to be submitted by the applicant only.

48. The FSAR incorporates by reference NEI 06-13, "Template for an Industry Training Program Description." The SER references NEI 06- 13A, Revision 1 as the acceptable template. Explain the discrepancy.

Staff Response: For the review of Section 13.2 of the STP FSAR, the staff used the most recently NRC accepted version of NEI 06-13, which is NEI 06-13A, revision 1. The applicant committed in its submittal to use NEI 06-13 for its reactor operator and nonlicensed plant staff training programs. Referencing NEI 06-13 as an acceptable template is not a problem because this version was endorsed as an acceptable methodology and is incorporated in its entirety into NEI 06-13A, revision 1.

49. In the draft license, the Staff proposes the following license condition:

> **"No later than 8 months before fuel is allowed onsite (protected area), NINA shall develop a written protective strategy that describes in detail the physical protection measures, security systems, and deployment of the armed response team relative to site-specific conditions, including but not limited to, the final facility layout, and the location of target set equipment and elements in accordance with 10 CFR Part 73, Appendix C.II.B.3.c.(v)."**

Final SER § 13.6 states: "However, the staff has not proposed any license condition implementation requirements for the STP COL application since the implementation milestones for these security programs are specified by 10 CFR 73.55(a)(4). Because the implementation milestones for these security programs are controlled by 10 CFR 73.55(a)(4) rather than by license condition, the applicant will need to update Table 13.4S-1 to reflect this."

a. Why is this license condition necessary? Were there similar conditions in previously-issued combined licenses?

b. Why is there a license condition for <u>developmen</u>t of the protective strategy in the draft license? The Staff's Final SER addresses <u>implementation</u> license conditions; is this the same thing?

Staff Response:

a. No, the license condition regarding development of the written protective strategy is not necessary. The applicant's proposed license condition relates to a specific time milestone for developing detailed implementing procedures for elements of the security programs prior to fuel onsite (protected area). A license condition for implementation of these elements of the security programs is unnecessary because overall implementation of the security programs is addressed by FSAR Section 13.4S and 10 CFR 73.55(a)(4).

   This is not a typical license condition that appeared in any of the previously-issued combined licenses. This license condition also has not been proposed by other COL applicants.

b. This license condition appeared in the draft license because the applicant proposed a more specific milestone for certain elements of the security programs. The proposed license condition was reviewed and accepted because the applicant demonstrated in sufficient detail the interdiction of an adversary force that supports the protection of vital equipment to address COL license information item 13.6.3.3.3. Providing design details after the issuance of the license is consistent with implementation of the security programs prior to operation of the facility. The proposed license condition appeared reasonable and the staff did not have technical objections to a specific milestone. The additional milestone provides greater detail for the planning of inspection activities.

   The "implementation" license condition discussed in final SER Section 13.6 is not the same as the license condition regarding the development of the protective strategy. In the context of final SER Section 13.6, "implementation" refers to the point at which the program is fully implemented (all required management systems have been established, including prepared detailed procedures; all personnel are trained; and SSCs and equipment are constructed, installed and available to execute the program).

   The inclusion of license conditions for operational program implementation was discussed in SECY-05-0197, "Review of Operational Programs in a Combined License Application and Generic Emergency Planning Inspections, Tests, Analyses, and Acceptance Criteria," dated October 28, 2005 (ML052770225). In SECY-05-0197, the staff recommended, among other things, that license conditions be included to specify the implementation of operational programs for which implementation requirements are not specified in the regulations. The staff included the security plans with these operational programs. In the Staff Requirements Memorandum (SRM), dated February 22, 2006 (ML060530316), the Commission approved the staff's recommendation. But with respect to the proposed security license condition, the Commission directed the staff to consider addressing the issues associated with this license condition in the next available rulemaking opportunity to avoid having to include the conditions in each license.

   The March 27, 2009 final rule, "Power Reactor Security Requirements," (74 FR 13926), included 10 CFR 73.55(a)(4) to specify implementation milestones for reactor security programs. Specifically, 10 CFR 73.55(a)(4) states, "[H]olders of a combined license under the provisions of part 52 of this chapter, shall implement the requirements of this section before fuel is allowed onsite (protected area)." The requirements of 10 CFR 73.55 include the Physical Security Plan, Training and Qualification Plan, Safeguards Contingency Plan, and Cyber Security Plan referenced in 10 CFR 73.55(a)(1). Because the implementation of these plans is specified by regulation, no license condition for their implementation was included in the draft STP Units 3 and 4 COLs, consistent with SECY-05-0197 and its associated SRM.

50. In the draft license, the Staff proposes the following license condition:

> **"No later than 8 months before fuel is allowed onsite (within the protected area), NINA shall develop a written protective strategy that describes in detail the cyber protection measures, systems, and deployment of the cyber security program relative to site-specific conditions to include, but not be limited to, the final facility design and the location of target set equipment and elements in accordance with 10 CFR 73.54."**

a. Why is this license condition necessary? Were there similar conditions in previously-issued combined licenses?

b. Why is there a license condition for development of the cyber security program but not the implementation as indicated in FSAR 13.4S-1?

Staff Response:

a. No, the license condition regarding development of the written protective strategy is not necessary. The license condition relates to a specific time milestone for developing detailed implementing procedures for elements of the cyber security program prior to fuel onsite (protected area). A license condition for implementation of these elements of the cyber security program is unnecessary because overall implementation of the cyber security program is addressed by FSAR Section 13.4S and 10 CFR 73.55(a)(4).

This is not a typical license condition that appeared in any of the previously-issued combined licenses. This license condition also has not been proposed by other COL applicants.

b. The license condition was reviewed and accepted because the applicant demonstrated in sufficient detail compliance with the cyber security regulations. Providing design details after the issuance of the license is consistent with implementation of the cyber security program prior to operation of the facility. At the time, the license condition appeared reasonable and the staff did not have technical objections to a specific milestone that would provide greater detail for the planning of inspection activities.

As stated in the response to Question 49, a license condition was not included for overall implementation of the cyber security program because the implementation of this program is specified in 10 CFR 73.55(a)(4). Specifically, 10 CFR 73.55(a)(4) requires COL holders to implement the requirements of 10 CFR 73.55 "before fuel is allowed onsite (protected area)." The cyber security plan is included in these 10 CFR 73.55 requirements, as indicated by 10 CFR 73.55(a)(1), (b)(8), (b)(9), (c)(6), (f)(2), and (m)(2).

51. The Staff issued RAI 17.04-5 requesting that NINA address in FSAR Subsection 17.4S.1.1.2 the interface responsibilities of the expert panel related to risk-significant structures, systems and components (SSCs) within the scope of the design reliability assessment program (D-RAP) that are not modeled in the applicant's probabilistic risk assessment (PRA). In response to the Staff's request, NINA added a commitment to the FSAR under which the licensee will identify and periodically review any proposed changes resulting in an increase in

the deterministically- established risk of an SSC not modeled in the PRA with the expert panel at a frequency determined by the panel.

a. Identify any plant-specific SSCs that are not modeled in the PRA and have been identified as risk-significant using a deterministic basis and explain why they are considered risk-significant.

b. If there are none that meet these criteria, then explain in general how SSCs are determined to be risk-significant when they are not modeled in the PRA.

Staff Response: During the April 21, 2011, ACRS subcommittee on ABWR (ML111220150), the applicant discussed examples of plant-specific SSCs that are not modeled in the PRA which have been identified as risk-significant using the deterministic method as described in FSAR Subsection 17.4S.1.4.2. The applicant identified examples including the Neutron Monitoring System (NMS), the Steam Bypass and Pressure Control System (SBPCS), and the High Pressure Core Flooder-Injection (HPCF) Isolation Valve E22-F003B, which are included in the D-RAP using the deterministic method. In addition, the staff confirmed during an audit that the deterministic method identified additional systems that are included in the D-RAP. These additional systems are identified in the audit report (ML15294A429). The staff notes that components and equipment within the identified risk-significant system are considered risk-significant. The staff found the applicant's deterministic method acceptable in accordance with the staff review guidance in SRP 17.4, "Reliability Assurance Program."

NINA's deterministic method uses a D-RAP expert panel to decide if an SSC should be identified as a D-RAP SSC using the following questions regarding the system function:

- Is the function used to mitigate accidents or transients?
- Is the function specifically called out in the Emergency Operating Procedures (EOPs) or Emergency Response Procedures (ERPs)?
- Does the loss of the function directly fail another risk-significant system?
- Is the loss of the function safety significant for shutdown or mode changes?
- Does the loss of the function, in and of itself, directly cause an initiating event?

The D-RAP list of risk-significant SSCs is updated and maintained as described in FSAR Subsection 17.4S.1.4.

52. SER, Ch. 19, Attachment A notes that NINA commits to locate spare batteries and chargers in suitable areas. In FSAR Part 11 (Mitigative Strategies Report, Fire Fighting Response Strategy), NINA states that an action has been added in the Corrective Action Program to locate communication device's spare batteries and chargers near the Control Room or other suitable areas (Commitment: 08-18140-11).

Explain why an action in a Corrective Action Program is being credited for a licensing basis document.

Staff Response: The staff understands that the Corrective Action Program is being used to track this commitment, but the Corrective Action Program is not being credited for a licensing basis document. Rather, Commitment 08-18140-11, is a commitment by STP Units 3 and 4 to

"Locate communication devices, spare batteries and charger near the control room or other suitable area." The milestone for completion of this commitment is "Prior to Fuel Load." In the staff's safety evaluation, the staff acknowledged STP Units 3 and 4's commitment by stating that, "The applicant commits to locate spare batteries and chargers in suitable areas."

53. STP Application Part 11-49 (Rev. 12) contains Commitment: 08-18140- 56, which provides that the considerations for equipment survivability and personnel accessibility within plant areas will be evaluated.

a. Can this issue be evaluated prior to issuance of a combined license?

b. How does this commitment demonstrate an acceptable strategy in the licensing basis?

<u>Staff Response</u>:

a. No, many of the items to be addressed in Phase One involve assessments, evaluations, action plans and procedural development that cannot be accomplished until a plant is near the completion of construction and therefore cannot be evaluated prior to issuance of a combined license. Commitment 08-18140-56 refers to Item 9 in the STP Unit 3 and 4 Phase One Mitigative Strategies Table. The Phase One items focus on the operational aspects of responding to explosions or fire, including planning and preparation activities (e.g., pre-positioning equipment, personnel, and materials to be used for mitigating the event), and developing procedures and training for the event. These items apply to programmatic aspects of a plant once it is operational and procedures are written and in-place to control processes. For STP Units 3 and 4, elements of responding to loss-of-large-area events will be addressed by the applicant prior to fuel load.

The staff's safety conclusion for COL issuance is supported by the applicant's description of how it will use NEI 06-12 for all three phases including this Phase One item. The staff's review concluded that the applicant meets the guidance and will ensure necessary equipment and personnel are pre-staged in such a manner that at least one location will survive a loss of large area due to fire or explosion.

b. It is acceptable to use commitments to address items that cannot be closed prior to COL issuance. This is consistent with the use of commitments for other Phase One items in this application and in other COL applications. Additionally, as stated in the STP Units 3 and 4 Mitigative Strategies Report, the milestone for Commitment 08-18140-56 is "Prior to Fuel Load."

54. Part 4 of the application, Limiting Condition for Operation (LCO) 3.8.11 states:

"The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems – Shutdown;"

b. Two or more diesel generators (DGs) capable of supplying the required OPERABLE features via the onsite Class 1E AC electrical power distribution subsystems required by LCO 3.8.10.

APPLICABILITY: MODE 4 and MODE 5 with water level in the refueling cavity < 7.0 meters above the reactor pressure vessel flange."

Surveillance Requirements SR 3.8.11.1 state: "For AC sources required to be OPERABLE, the SRs of Specification 3.8.2 are applicable." However, Specification 3.8.2, AC Sources – Refueling is applicable for MODE 5 with water level in the refueling cavity > 7.0 meters above the reactor pressure vessel flange.

Are there surveillance requirements for MODE 4?

<u>Staff Response</u>: There are surveillance requirements (SRs) for MODE 4 under SR 3.8.11.1. Specifically, SR 3.8.11.1 references the surveillance requirements identified in technical specification (TS) limiting condition for operation (LCO) 3.8.2, i.e., SR 3.8.2.1. Although the applicability statement for LCO 3.8.2 references MODE 5 and not MODE 4, that statement does not apply here. Rather, the applicability statement of LCO 3.8.11 applies. LCO 3.8.11 is governed by its own applicability statement, which includes MODE 4.

55. Please provide more detail as to why NINA's response to the following RAIs resulted in regulatory commitments in the FSAR as opposed to license conditions.

1) In response to RAI 19-30 dated July 28, 2010 (ML102110184), and as discussed in Appendix 19R of the SER, NINA revised COL FSAR § 2.4S.10, "Flooding Protection Requirements," to state that all watertight doors and hatches are normally closed.

2) The Staff concluded that the issues associated with Open Item 19-9 (RAI 19.01-31) are resolved based on: the results of the quantitative assessment and sensitivity analyses that satisfy the requirements of 10 C.F.R. § 52.79(d)(1); completion of the specific bulleted requirements (referenced in FSAR § 19.4.6, "Shutdown Risk") in the abnormal operating procedures to address hurricane preparations, which will assure that the risk from hurricanes for STP Units 3 and 4 remains below the Commission goals; and completion of these requirements, which will assure that the STP Units 3 and 4 design has levels of defense-in-depth.

<u>Staff Response</u>: The licensing bases for a nuclear power reactor can be represented by a few categories of information that form a hierarchy structure (e.g., license conditions, regulatory commitments in the FSAR, licensee controlled regulatory commitments). Associated change controls and reporting requirements are based on this hierarchy. After a significant amount of review and discussions with the applicant on the topics of flood protection and hurricane preparations, the staff determined that regulatory commitments in the FSAR provide an acceptable degree of regulatory oversight. The administrative control measures documented as regulatory commitments in the FSAR ensure that flood and hurricane risk remain within the large release frequency Commission goal that is used as a surrogate for the prompt fatality quantitative health objective. Regulatory commitments included in the FSAR are subject to a formal regulatory change control process as described in 10 CFR 50.59. If any of the thresholds in 10 CFR 50.59(c) are exceeded, prior NRC approval would be required in the form of a license amendment. This process provides an appropriate degree of regulatory control, since adherence to the requirements of 10 CFR 50.59 provides reasonable assurance of safety. Also, specific administrative procedures are not typically license conditions. Additional regulatory control is provided by the NRC's inspection process, since changes to these flooding protection and hurricane preparation measures are subject to this inspection process.

56. In Chapter 22, the Staff states that NTTF Recommendation 5.1, "Reliable Hardened Vents for Mark I and Mark II Containments," is not applicable "because it applies to boiling-water reactor (BWR) type plant designs with Mark I and Mark II Containments, which differ significantly from the Advanced Boiling Water Reactor (ABWR) containment." In SER § 1.4S.4.1, the Staff states, "the ABWR containment combines design features of Mark II and Mark III containments." Section 6.2.1.1 of the SER states:

> **This primary containment design basically uses combined features of the Mark II and Mark III designs, except that the drywell consists of UD [upper drywell] and LD [lower drywell] volumes. The vents to the suppression pool are a combination of the vertical Mark II and horizontal Mark III systems. The wetwell is similar to a Mark II wetwell.**

In addition, the drywell and wetwell free volume of the ABWR is approximately 0.47 E6 ft^3 and the containment design pressure is 45 psig. The BWR Mark II design parameters are a free volume of 0.4 E6 ft^3 and containment design pressure of 45 psig.

Please describe in more detail any significant design differences between the ABWR and BWR Mark II containments that justify no further review by the Staff of NTTF Recommendation 5.1.

<u>**Staff Response**</u>**:** Although the ABWR containment design bears some similarities to BWR Mark II and III containments, NTTF Recommendation 5.1 applies only to the BWR Mark I and II designs. NTTF Recommendation 5.2, "Reliable Hardened Vents for Other Containment Designs," applies to the ABWR.

For nuclear power plants licensed under 10 CFR Part 52, the NRC imposes additional requirements for containments beyond those for currently operating plants. This practice is consistent with the NRC's Severe Accident Policy Statement that new nuclear power plants should incorporate improvements during design and construction that were not practical or cost-effective to require as modifications to existing plants. New reactors licensed under 10 CFR Part 52 must address similar design basis accidents as operating plants, and must also have severe accident design features to increase the ability of containments to maintain their integrity during severe accident conditions.

The ABWR design referenced in the STP Units 3 and 4 application contains design differences when compared with currently operating BWR Mark I and II containments. The STP Units 3 and 4 containments have a specific design feature to increase the ability of its containment to maintain its integrity during severe accident conditions and maintain containment integrity during a simultaneous extended loss of all alternating current power (ELAP) concurrent with a loss of normal access to the ultimate heat sink (LUHS). The design feature is called the containment overpressure protection system (COPS). The COPS is a hardened vent system consisting of two overpressure relief rupture disks that relieve pressure from the top of the suppression pool air space to the atmosphere via the plant stack. Once the COPS rupture disk relieves, containment pressure and temperature decrease. Additionally, STP Units 3 and 4 have several other design features to mitigate severe accidents, which the staff concluded meet the applicable requirements. These design features include: ac-independent water addition system (provides lower drywell flooding and upper drywell spray), lower drywell flooder (provides alternate cavity flooding with thermally activated flooder valves), vessel depressurization, lower drywell design (a sacrificial, low gas content concrete), inerted containment (minimizes the impact from combustible gases), and drywell-wetwell vacuum breakers (located high in the wetwell to protect the vacuum breakers from pool swell loads).

57. NINA proposed several exemptions to otherwise-applicable regulatory requirements in its application. Please discuss how the Staff's environmental review in the FEIS captured the exemptions.

Staff Response: The staff's environmental review in the final environmental impact statement (FEIS) captures the exemptions as part of the proposed action by the applicant. The applicant's proposed action to construct and operate two new nuclear units included requests for exemptions from information in the ABWR design certification under 10 CFR Part 52, Appendix A, Section VIII. The environmental impacts of these requested exemptions are therefore included in the staff's evaluation of the environmental impacts of the proposed action in the STP Units 3 and 4 FEIS.

The applicant requested three additional exemptions. The first, requested March 23, 2010, was associated with crane foundation walls and was addressed under a separate environmental assessment prepared by the NRC staff (ADAMS Accession No. ML102770454) where staff found there was no significant impact. The remaining two were associated with the Special Nuclear Material Control and Accounting Program (requested October 27, 2011) and financial qualification (requested June 19, 2014). These were reviewed after the FEIS was issued as part of the evaluation of new information, and neither have environmental impacts.

58. The Staff's environmental standard review plan is currently being updated to reflect environmental requirements established after 2007. The FEIS was published February 2011. What, if any, review was done to ensure the FEIS addresses all current requirements?

Staff Response: The staff's New and Significant Process was used by the staff to identify potentially significant new information after the draft environmental impact statement (DEIS) or FEIS is issued, determine its significance, and consider whether this information requires supplementation of the DEIS or FEIS, and is described in "Staff Process for Determining if a Supplement to an Environmental Impact Statement is Required in Accordance with Title 10 of the *Code of Federal Regulations*, Part 51.92(a) or 51.72(a)" (ADAMS Accession No. ML13199A170). The staff followed this guidance to identify and evaluate potentially significant new information for the STP Units 3 and 4 COL application. 10 CFR 51.92 requires that the EIS be supplemented if there are substantial changes in the proposed action that are relevant to environmental concerns or if there are new and significant circumstances or information relevant to environmental concerns and bearing on the proposed action or its impacts.

The three phases of this process are: (1) identify new information, (2) evaluate and document the new information to determine if it is significant, and (3) determine whether supplementation is required. To address new requirements, the staff keeps up with changes in regulation and policy in areas that could affect the DEIS or FEIS.

As part of this post-FEIS review for STP Units 3 and 4, the NRC staff conducted an audit in February 2015 of the applicant's process for identifying and assessing new information (ADAMS

Accession No. ML15040A372). The staff found that the applicant had an acceptable process and reviewed numerous changes, including changes to environmental regulations. Staff analyzed these changes and determined that none of the new information warranted a supplement to the STP Units 3 and 4 FEIS.

Based on this analysis, the staff concluded that the new information did not present a seriously different picture of the environmental impacts of the proposed action when compared to the impacts that were described in the FEIS for STP Units 3 and 4. After following the New and Significant Process, the staff determined that it had not identified any new information that warranted a supplement to the STP Units 3 and 4 FEIS.

59. In SECY-15-0123 (page 30), the Staff describes its process for searching for new and significant information with respect to the FEIS. The Staff notes that it conducted an audit of NINA's process for identifying new and significant information and references an Audit Report from 2015 on this topic. However, the Audit Report notes several follow up actions and unanswered questions. Specifically the audit team intended to conduct further reviews of cumulative impacts analyses, tribal consultations, the Colorado River salt wedge, and whether any additional information provided by NINA required supplementation of the FEIS. Please provide additional updates on these activities. Has the Staff completed its review of whether any of this information constituted new and significant information requiring a supplement to the FEIS?

Staff Response: The staff has completed its review of new information for STP Units 3 and 4. Based on this review, the staff concludes that the new information does not present a seriously different picture of the environmental impacts of the proposed action when compared to the impacts that were described in the FEIS for STP Units 3 and 4. The staff determined that no supplement to the FEIS is required.

After the audit held in February 2015, the NRC audit team closely reviewed Table 7-1, "Past, Present, and Reasonably Foreseeable Future Projects and Other Actions Considered in the STP Cumulative Analysis," in Chapter 7, "Cumulative Impacts," to determine which projects or other actions were cancelled or added since the FEIS was issued. The staff determined that with the cancellation of some projects (e.g., the 2010 Lower Colorado River Authority – San Antonio Water System project) and addition of others (e.g., 2017 Lane City Reservoir), the impact determinations would not change.

The staff evaluated the need for additional Tribal consultations and concluded that additional consultations were not warranted. The review included a discussion with the NRC staff who developed the license renewal EIS for STP Units 1 and 2 to better understand the Tribal consultations conducted for their review. In addition, neither the area of potential effects nor any historic properties within it have changed. Additional consultation with Tribes is neither required nor expected for STP, because the staff had completed historic property identification and evaluation efforts and found that no historic properties are affected.

The NRC audit team also looked into the possibility of a salt wedge migration in the Lower Colorado River. Lower flow rates in the Colorado River could result in a salt wedge travelling further up the river due to reduced flow pressure. The proposed site for STP Units 3 and 4 has been in a drought since 2010 which has affected flows in the Colorado River. Through three conversations with the Lower Colorado River Authority and follow-on analysis, the NRC staff determined that these flow fluctuations have not caused any additional impacts to the salt wedge than were presented in NUREG-1937.

Other information reviewed included other effects of the drought and changes to the listed threatened and endangered species. As stated above, the staff found that no supplement was needed based on analysis of new information.

60. Throughout the FEIS, the Staff frequently references NUREG-1437, the NRC's generic environmental impact statement for nuclear power plant license renewals. Since the publication of the FEIS, the agency has issued a revised version of NUREG-1437. Has the Staff taken steps to ensure that the revisions to NUREG-1437 did not impact the analyses in the FEIS?

Staff Response: Yes, the staff has taken steps to ensure that the revisions to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants" (originally published in 1996, herein noted as the 1996 GEIS - ML040690705, ML040690738, and ML040690720, and revised in 2013, herein noted as the 2013 GEIS – ML13107A023) did not impact the analyses in the STP FEIS. The staff applies NUREG-1437 in areas of the environmental review where the environmental impacts of a new reactor are expected to be similar to the impacts from current operating reactors. These areas are consistent across all new reactor EISs.

As such, the staff's evaluation of whether the 2013 GEIS impacted the STP EIS conclusions was based on the staff's evaluation of the 2013 GEIS in support of new reactor EIS work ongoing at the time of the 2013 GEIS publication. The staff had three EISs under review in June 2013. To assure the information applied from the 1996 GEIS remained valid, the staff, including subject matter experts, evaluated whether the information in the 2013 GEIS altered the information in the 1996 GEIS. The staff found that the information used for new reactors (i.e., impacts and findings) were essentially unchanged in the 2013 GEIS and remained valid for use. Thus, the staff concluded that the 1996 GEIS as considered in the STP COL FEIS remains valid.

61. If the Staff had directly considered the environmental impacts of spent fuel storage, as described in the Continued Storage GEIS, NUREG-2157, what effect, if any, would that consideration have had on the benefit-cost balance described in Chapter 10, section 6, and the evaluation of alternatives in Chapter 9?

Staff Response: On July 2, 2015, the NRC staff completed its evaluation of the potential for the new information related to the continued storage rule to affect its conclusions in the STP FEIS (ML15096A156). The staff concluded that the new information related to the revised rule did not paint a seriously different picture of the environmental impacts of the proposed action when compared to the impacts that were described in the FEIS for STP Units 3 and 4. Had the information related to the revised rule been available at the time the STP FEIS was being written, the staff would have applied logic similar to that described in the July 2, 2015 evaluation to its consideration of the associated environmental impacts. The staff would have concluded that the impacts of the radiological wastes from the fuel cycle would be SMALL. For an example of the treatment of this issue for an EIS that was written after the rule changed, see Section 6.1.6 of the DEIS for the Turkey Point Units 6 and 7 combined license application (ML15055A103).

In summary, the new information related to the impacts of the continued storage of spent fuel would not have changed the staff's conclusions regarding the alternatives or the benefit-cost balance.

62. Highlight major themes from the comments on the Draft Environmental Impact Statement (DEIS), and generally describe the Staff's responses to those comments.

<u>Staff Response</u>: The staff issued the STP DEIS on March 26, 2010, for public comment. The staff held transcribed public meetings in Bay City, Texas on May 6, 2010, to collect comments from interested stakeholders in the area of the proposed project. During the 75 day comment period, the staff received 11 letters and e-mail messages with comments and 57 of the 175 attendees provided their comments at the public meeting. The staff addressed 378 individual comments extracted from the meeting transcripts, letters, and emails.

Some comments addressed topics and issues that are not part of the environmental review for this proposed action. These comments included questions about the NRC safety review, general comments of support or opposition to nuclear power, and a comment on security and terrorism. With respect to these comments, the staff generally either acknowledged the commenter's general support for or opposition to the application or explained why the matter raised was not within the scope of the staff's environmental review.

With respect to those comments on topics within the scope of the staff's environmental review, the major themes identified by the staff related to the areas of hydrology (both surface and ground water), need for power, socioeconomics, energy alternatives, benefit-cost balance, radiological health, site layout and design, ecology (both aquatic and terrestrial), and meteorology and air quality. The staff responded to the commenters' concerns, generally directed the commenter to the section of the FEIS where the issue was evaluated, and indicated whether or not that section had been revised as a result of the comment. Most responses included a brief explanation of how a section of the FEIS was revised, or why a section was not revised.

63. The area where STP is located has been in a drought since 2010 and flows in the Colorado River have been affected. How have the drought conditions been taken into account to ensure that the STP site is still the obviously superior site?

<u>Staff Response</u>: As directed by the staff's guidance in the Environmental Standard Review Plan (NUREG-1555), the staff concluded in Section 9.3.5.3 of the FEIS for STP Units 3 and 4 that none of the alternative sites was either environmentally preferable or obviously superior when compared to the proposed site.

The staff recognizes that 2011 was the driest year on record for Texas. The State remained in severe drought condition from late 2010 until recently. Since the FEIS was published in February 2011, this information was new. In order to determine the validity of the staff's evaluation in the FEIS, on March 27, 2015, the staff had a teleconference with the Lower Colorado River Authority (LCRA) staff. The LCRA mentioned that the effect of the drought of the 2010s on the Highland Lakes region was more severe than on the Lower Colorado River (ML15097A470).

For its evaluation of drought conditions in the FEIS, the staff considered the drought of record that occurred in the 1950s, recognizing that Texas experiences frequent droughts. The staff documented its analysis in Section 2.3.1.1 of the FEIS. The staff used the mean annual discharge data at the U.S. Geological Survey gage 08162500, Colorado River near Bay City, Texas in its analysis. Because the severe drought of the 2010s was bounded by the drought of record of the 1950s as recorded at the Colorado River gage near Bay City, the staff's impact evaluation did not change.

The NRC staff evaluation of the impact of the recent drought on groundwater was based on three main factors:

1) Changes in Matagorda County mean annual precipitation since FEIS publication (including the drought),

2) Resulting changes in groundwater levels in the region and at the site, and

3) Changes in groundwater usage.

The mean annual precipitation over Matagorda County discussed in FEIS Section 2.3.1.2, was determined using historic data (1940-2002) and ranged from 42 to 46 inches. Using more recent precipitation data available from the National Climatic Data Center, the staff determined that the mean annual precipitation from 2003-2014 was 1.6 inches lower than the mean value (43.8 inches per year) calculated from data available through 2002. This indicates that reduction in precipitation during the drought years was not enough to significantly alter the mean annual precipitation for Matagorda County and is still within the range used in the FEIS.

As discussed in FEIS Section 2.3.1.2, modeling indicates that in the gulf coast of Texas small changes in precipitation result in even smaller changes in groundwater levels in the underlying aquifers. In this case, the reduction in mean annual precipitation since 2002 would result in a small (0.06 in/year) decrease in recharge which would not affect groundwater levels. This is supported by the 2011 Region K Water Plan for the Lower Colorado Regional Water Planning Group which concluded that the Gulf Coast Aquifer is resistant to drought and recovers completely from drawdown. It is further supported by data from site wells which was gathered during the drought and indicates that there have been no long term significant declines in water levels.

Finally, STP had reduced the average groundwater withdrawal at the proposed site since issuance of the FEIS and expects future usage to remain at or below this reduced level.

As a result, the staff determined that new information, including the recent drought would not change impact conclusions reached in the FEIS. The evaluation above was documented by the staff in the new and significant review.

64. Explain the analysis, if any, that was completed to show that the drought referenced in Question 63 had no impacts on terrestrial/ecology conclusion in the FEIS.

Staff Response: The staff did not perform a separate analysis of the effects of the 2010s drought on terrestrial ecological resources. Native ecosystems are a product of the history of environmental conditions in the landscape and are made up of regionally adapted populations of species that are capable of withstanding most periodic extreme events such as the 1950s and 2010s droughts. Furthermore, the EIS notes on Page 2-49 that "The existing plant associations on the STP site consist primarily of successional vegetation occurring on old abandoned agricultural fields and pastures" and on Page 2-67 that "the proposed location of Units 3 and 4 consists primarily of previously developed lands (warehouses, parking lots, laydown yards, etc.), a mowed field, and a relatively open shrubland area …". Not only can the ruderal (weedy) plants and opportunistic wildlife characteristic of such areas be expected to be broadly tolerant to extreme environmental conditions such as droughts, but loss or degradation of those resources would be of only minimal ecological significance even if it were to occur. The staff therefore does not expect that any of the corresponding environmental impact determinations would change.

65. In a letter dated September 16, 2010 (ML103020111), the U.S. Army Corps of Engineers (USACE) provided a copy of the Unified Stream Methodology assessment conducted on relatively permanent waters along the Colorado River, in Matagorda County, indicating that STP should submit a compensatory mitigation plan for the proposed dredging and filling associated with STP Units 3 & 4. Has NINA since received the USACE permit under Clean Water Act § 404? If not, discuss the expected schedule for issuance.

<u>Staff Response</u>: By letter dated July 31, 2013 (ML13220A233), NINA provided the USACE permit (Permit No. SWG-2007-00786) issued under Clean Water Act § 404 to the NRC.

66. In 2014, the Environmental Protection Agency (EPA), under Clean Water Act § 316(b) issued regulations for industrial cooling systems that may apply to new units at existing facilities. FEIS § 3.2.2.2, at 3-7, states that the review team concludes that Units 3 and 4 and the intake structure on the Colorado River that supports their operation would not qualify as a "new facility," but rather qualify as an "existing facility." The Staff also acknowledged that the EPA was developing regulations that address cooling water systems for existing facilities, which would be applicable to STP Units 3 and 4. EPA issued those regulations in 2014.

Please describe the status of this issue.

<u>Staff Response</u>: The FEIS (Pages 3-6 and 3-7) describes the reservoir makeup pumping facility (RMPF or intake structure). As part of that discussion the staff concluded that STP Units 3 and 4 should be considered an "existing facility" and not be subject to the requirements of EPA's 316(b) Phase I regulations (66 FR 65256) pertaining to intake structures for "new facilities." EPA was developing new regulations for intake structures at existing facilities at the time the FEIS for STP Units 3 and 4 was published. On August 15, 2014, EPA published 316(b) regulations (79 FR 48300) for existing facilities that provide requirements that reflect the best technology available (BTA) for minimizing impacts related to impingement and entrainment at cooling water intake structures. The regulations also clarified the definition of an "existing facility." Based on the new regulations, the staff reaffirmed its conclusion that STP Units 3 and 4 are considered "existing facilities" because the site has an existing facility and intake structure and that the design capacity of the cooling water intake structure has not been increased. The existing RMPF on the STP site was originally built to accommodate four units.

The 2014 regulations require "existing facilities" to comply with one of seven alternatives identified in the national BTA standard for impingement mortality (79 FR 48321). STP Units 3 and 4 comply with the first of the seven alternatives – the use of a closed-cycle recirculating station cooling system. The use of an impoundment that is not waters of the U.S. to serve as a cooling reservoir is considered equivalent to a closed-cycle recirculating station cooling system (79 FR 48307). For entrainment the 2014 rule does not prescribe a single nationally applicable entrainment performance standard but instead requires that the National Pollutant Discharge Elimination System (NPDES) Permit Director establish the BTA entrainment requirement on a site specific basis (79 FR 48322).

Based on the use of the cooling impoundment, the planned frequency of pumping of water, the location of the traveling screens, the traveling screen approach velocity, and the fish return system the staff concluded that the impact of impingement and entrainment for proposed STP

Units 3 and 4 would be minor. The applicant complies with the BTA requirement for impingement by utilizing a closed-cycle cooling system. The planned use of a fish return system and minimizing screen approach velocities to approximately 0.5 feet per second or less would further reduce impingement mortality. For entrainment there is the possibility that at the time NINA applies for an NPDES permit for STP Units 3 and 4 the NPDES Permit Director may require additional BTA measures to reduce entrainment losses. However, since the staff determined in the FEIS that impacts to the fishery from entrainment losses would be minor, any further reduction in losses associated with the imposition of BTA requirements by the Director would further reduce an already minor impact.

67. Have there been any new threatened or endangered species listed by State or Federal entities since the FEIS was completed in 2011? If so, how have they been or will they be addressed?

Staff Response: According to the U.S. Fish and Wildlife Service (FWS) Information for Planning and Conservation (IPaC) website, only one new species that has been Federally listed as threatened or endangered potentially occurs in the landscape surrounding the STP site: the rufa red knot (*Calidrus canutus rufa*). The rufa red knot was listed as threatened under the Endangered Species Act on December 11, 2014 (79 FR 73705 - 73748). It is a migratory shorebird that breeds in the Canadian Arctic, winters in parts of the United States (including the Texas coast) and Central and South America, and migrates primarily along the Atlantic coast (79 FR 73705 - 73748). In February 2015, the staff conferred with wildlife experts representing the applicant and our cooperating agency, the U.S. Army Corps of Engineers (USACE). The applicant's expert stated that the STP site does not provide suitable habitat for the rufa red knot and that the species' preferred habitat, which consists of beachfront and shores, occurs 15 to 17 miles south of the site. The USACE expert stated that the rufa red knot uses the same habitat as the piping plover (*Charadrius melodus*), another shorebird listed as threatened that favors beach habitats, and that piping plover habitat does not occur on the STP site. Based on its review of the information provided by the applicant's and USACE's experts, the staff therefore concludes that the STP project would have no effect on the rufa red knot. Federal agencies are not required to seek concurrence from the FWS for conclusions of no effect on listed species. The staff is therefore not required to take any further action under the Endangered Species Act.

As part of its recently completed review of new and significant information, the staff identified no new state-listed aquatic or terrestrial threatened or endangered species in the area containing the STP Units 3 and 4 site. Although the statuses and county distributions of certain state-listed species have changed since the FEIS, the staff concluded as part of the new and significant information review that the changes would not alter the FEIS's ecology conclusions.

68. A letter dated June 4, 2008 (ML081610296) describes a commitment by STPNOC (NINA's predecessor) to develop a procedure for discovery of cultural or historical artifacts during construction. Where will this commitment be captured, and how will the Staff ensure the commitments are met?

Staff Response: The commitment to develop a procedure was met when the applicant submitted its procedure for discovery of cultural or historical artifacts during construction under oath or affirmation by letter dated June 9, 2008 (ML081640213).

69. In February 2010, the State of Texas waived its authority under Title 30, Texas Administrative Code, Chapter 279.2(b)(4) (ML100500926) to act on STPNOC's request for water quality certification. Please explain how this action meets the

requirement to have the Clean Water Act § 401 certification required for the NRC to issue a license.

Staff Response: Section 401 of the Clean Water Act gives States and authorized Tribes the authority to issue a State Water Quality Certification (401 Certification) for an activity that may result in a discharge to waters of the U.S. and that requires a Federal permit or license. A Federal agency can issue a permit or license after the State has certified, conditionally certified or waived the 401 Certification in accordance with 33 U.S.C. 1341(a)(1) et seq.

In the case of STP Units 3 and 4, the State of Texas waived the 401 certification to avoid duplicate regulatory review of activities (discharges to the waters of the U.S.) that will be evaluated under separate permitting processes for Section 402 (NPDES Permits) or Section 404 (Fill Permits). The waiver concludes the Section 401 certification process in one of the three ways that meet the Section 401 requirements to allow Federal agency licensing. This is the first time that a new reactor project has moved forward to mandatory hearing with a 401 certification waiver.