

Final Safety Evaluation Report

Related to the Certification
of the Economic Simplified
Boiling-Water Reactor
Standard Design

Volume 4 (Chapters 16 – 24)

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ABSTRACT

This final safety evaluation report documents the technical review of General Electric-Hitachi's (GEH's) Economic Simplified Boiling-Water Reactor (ESBWR) design certification. GEH submitted its application for the ESBWR design on August 24, 2005, in accordance with Subpart B, "Standard Design Certifications," of 10 CFR Part 52. The NRC formally docketed the application for design certification (Docket No. 52-010) on December 1, 2005.

The ESBWR design is a boiling-water reactor (BWR) rated up to 4,500 megawatts thermal (MWt) and has a rated gross electrical power output of 1,594 megawatts electric (MWe). The ESBWR is a direct-cycle, natural circulation BWR that relies on passive systems to perform safety functions credited in the design basis for 72 hours following an initiating event. After 72 hours, non-safety systems, either passive or active, replenish the passive systems in order to keep them operating or perform post-accident recovery functions directly. The ESBWR design also uses non-safety-related active systems to provide defense-in-depth capabilities for key safety functions provided by passive systems. The ESBWR standard design includes a reactor building that surrounds the containment, as well as buildings dedicated exclusively or primarily to housing related systems and equipment.

On the basis of its evaluation and independent analyses, as set forth in this report, the NRC staff concludes that GEH's application for design certification meets the requirements of 10 CFR Part 52, Subpart B, that are applicable and technically relevant to the ESBWR design. Appendix F includes a copy of the report by the Advisory Committee on Reactor Safeguards, as required by 10 CFR 52.53.

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16.0 TECHNICAL SPECIFICATIONS

16.1 Introduction and Regulatory Criteria

GE-Hitachi Nuclear Energy (GEH) modeled most of the generic technical specifications (TS) and generic TS bases for the economic simplified boiling-water reactor (ESBWR) after Revision 3 of NUREG-1434, "Standard Technical Specifications, General Electric Plants, BWR/6." In a few cases, such as containment systems, the applicant adapted TS requirements from Revision 3 of NUREG-1433, "Standard Technical Specifications, General Electric Plants, BWR/4". The applicant developed these standard technical specifications (STS) from the results of the TS improvement program, in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 50.36 and SECY-93-067, "Final Policy Statement on TS Improvements for Nuclear Power Reactors" dated July 22, 1993. As required by 10 CFR 52.47(a)(11), a standard design certification application must include proposed generic technical specifications (GTS) as a part of the final safety analysis report (FSAR). The GTS must be prepared in accordance with the requirements of 10 CFR 50.36 and 10 CFR 50.36a. The applicant states that the ESBWR GTS and GTS bases comply with 10 CFR 50.36(c)(2)(ii), which requires the TS to include a limiting condition for operation (LCO) for each item meeting one or more of the following four criteria:

- Criterion 1 – Installed instrumentation that is used to detect, and indicate in the control room (CR), a significant abnormal degradation of the reactor coolant pressure boundary
- Criterion 2 – A process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier
- Criterion 3 – A structure, system, or component (SSC) that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier
- Criterion 4 – An SSC shown by operating experience or a probabilistic safety assessment to be significant to public health and safety

The review of the GTS and bases by the staff of the U.S. Nuclear Regulatory Commission (NRC) concentrated on the differences between these documents and the STS and STS bases. Such differences result from the new passive systems design, structural differences from existing systems, and the advanced microprocessor-based instrumentation and control (I&C) system, as well as shutdown operations, including a new safe-shutdown operational mode.

During its review, the staff forwarded its comments on the proposed GTS and GTS bases to the applicant for resolution and incorporation into the final GTS and bases. The final GTS and bases, included in design control document (DCD), Tier 2, Revision 9, Chapters 16 and 16B, respectively, provide resolution of the staff's issues, described as appropriate in this safety evaluation report (SER), and are certified to be accurate by the applicant. It should be noted that the GTS and the GTS bases are not Tier 1, Tier 2*, or Tier 2 information. However GTS Section 16.0 is Tier 2 information.

16.2 Staff Evaluation

16.2.0 General Considerations

The staff evaluated the GTS to confirm that they will preserve the validity of the plant design, as described in the ESBWR DCD, by ensuring that the plant will be operated (1) within the required conditions bounded by the ESBWR DCD and (2) with operable equipment that is essential to prevent ESBWR postulated design-basis events or mitigate their consequences.

Request for Additional Information (RAI) 16.0-1 The staff assessed the ESBWR GTS to confirm that the applicant had established an LCO for any aspect of the design that meets one or more of the four criteria outlined in 10 CFR 50.36(c)(2)(ii). The staff based this assessment partially on the applicant's response to the staff's request in RAI 16.0-1, which asked the applicant to explain how it formulated the LCOs for the ESBWR GTS and ensured that the GTS satisfied the requirements of 10 CFR 50.36. In response, the applicant stated that it had completed a "systematic and comprehensive evaluation of Revision 1 of the ESBWR DCD to determine the ESBWR process variables, design features, operating restrictions, and structures, systems, and components that meet one or more of the four criteria in 10 CFR 50.36(c)(2)(ii)." However, significant changes in the ESBWR design, as described in several subsequent revisions of the DCD, prompted the staff to ask the applicant to update its response. RAI 16.0-1 was tracked as an open item in the SER with open items. In the update to its original response, the applicant stated that it had continuously assessed how changes in the ESBWR design and responses to RAIs may have impacted the original response to RAI 16.0-1. The staff determined that, by carefully reviewing the change lists provided by GEH with each DCD revision, it was able to verify that the GTS include LCOs for all SSCs and parameters required by the four LCO criteria identified in 10 CFR 50.36. Therefore, RAI 16.0-1 is resolved.

The ESBWR design includes safety systems that are both innovative and simplified. It employs passive safety-related systems that rely on gravity and natural processes, such as convection, evaporation, and condensation. Although the applicant modeled the GTS after the STS to the maximum extent practical, it was necessary to develop GTS beyond those in the STS to account for the passive design features of the ESBWR. However, in most cases, the ESBWR system design functions are similar to those of existing boiling-water reactors (BWRs), even though the components and systems are new. The staff also requested that the applicant model the GTS after the equivalent STS safety functions. In those cases in which the staff believed deviation from the STS was appropriate to account for ESBWR design features, the required action completion times and surveillance requirement (SR) frequencies associated with the LCOs were maintained consistent with the STS provisions for the equivalent safety function.

The applicant determined that 10 CFR 50.36(c)(2)(ii) does not require establishing GTS LCOs for most active nonsafety systems. However, following the guidance in SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs", the applicant proposed establishing an ESBWR availability controls manual (ACM), which is described in DCD Tier 2, Revision 9, Chapter 19A. The applicant's evaluation of nonsafety-related systems against the regulatory treatment of nonsafety systems (RTNSS) significance criteria identified those nonsafety-related SSCs which require high regulatory oversight in the form of GTS LCOs; those nonsafety-related SSCs which require low regulatory oversight in the form of short-term availability controls, and which are included in the ACM; and those nonsafety-related SSCs which require only the oversight imposed by 10 CFR 50.65 (referred to as the Maintenance Rule). Section 22.5 of this report provides the staff's evaluation of the ESBWR RTNSS.

In some instances, establishing the site-specific information to be included in the plant-specific TS (PTS) and PTS bases, which are issued with a combined license (COL), requires design details, equipment selections, instrumentation settings, or other information that cannot be provided during the design certification process. Locations in the GTS for the addition of this information are signified by square brackets to indicate that the COL applicant must provide plant-specific values or alternative text in the PTS and justify this information in the combined license application (COLA). GEH addressed this COLA requirement in the introduction to DCD Tier 2, Revision 4, Chapter 16, by proposing COL Information Item 16.0-1, which stated the following:

This set of generic technical specifications is provided as a guide for the development of plant specific technical specifications. Combined License applicants referencing the ESBWR will replace the preliminary information provided in “square brackets” (“[...]”) with final plant specific information. The guidance of associated Reviewer’s Notes included (typically in Chapter 16B) in the generic Technical Specifications is for information only and is deleted on completion of the COL Item.¹

RAI 16.0-2 The staff asked the applicant to consider how to avoid ambiguous use of brackets in the GTS and bases. In response, the applicant committed to use square brackets only when indicating information that a COL applicant would be expected to provide. Where necessary, GEH will add a reviewer’s note to clarify what information is expected. For example, if the choice of information depends on whether conditions stated in a topical report are met, the DCD will provide a reviewer’s note directing the COL applicant to address in its application how it satisfied those conditions. The applicant also stated in its response that, during the course of the design certification review, it will use curly brackets in any interim revisions of DCD Chapters 16 and 16B to denote information that must be finalized. The applicant stated that it would finalize such information by the completion of the ESBWR design certification review and remove the curly brackets. DCD Tier 2, Revision 3, Chapter 16 reflected this commitment. Therefore, RAI 16.0-2 is resolved.

The staff tracked RAI 16.0-2 as a confirmatory item (i.e., Confirmatory Item 16.0-2) to ensure that the applicant completed changes to DCD Chapters 16 and 16B based on its commitment to remove all curly brackets and limit the use of square brackets to information associated with COL Information Item 16.0-1. However, after receipt of DCD Revision 4, the staff decided that it would track the disposition of bracketed information under RAI 16.2-164, as discussed below. Therefore, Confirmatory Item 16.0-2 is considered complete.

RAI 16.2-164 In Revision 4 of the DCD, the applicant revised its intended use for curly brackets to denote only information that cannot be provided until after the COL is issued. The applicant stated it would propose a license condition requiring completion of such information in the PTS at an appropriate time interval before initial fuel load. In response, the staff sent the applicant RAI 16.2-164, which states the following:

¹ COL Information Item 16.0-1 collectively refers to all instances of bracketed site-specific information placeholders in DCD Tier 2, Revision 9, Chapters 16 and 16B. Each instance is associated with a unique “COL Item” serial number, which includes the number of the GTS subsection containing the instance (e.g., “COL Item 3.1.3-2” denotes bracketed placeholders in GTS 3.1.3 for site-specific information related to control rod scram time limits). Each “COL Item” includes one or more placeholders in a GTS subsection. DCD Tier 2, Revision 9, Section 16.0, Table 16.0-1-A provides COL applicants guidance for completing each “COL Item.”

In Revision 4 of the ESBWR DCD Chapter 16, GEH proposes to change the definition of a curly bracket from a value, parameter, or information that will be provided by the design certification applicant to a value, parameter, or information that will be provided by the combined license (COL) holder. This proposed change is unacceptable. All the curly brackets need to be removed during the design certification review unless the information is closely associated with design acceptance criteria (DAC) or is site specific. In the latter two cases, the brackets can be changed to square brackets. Please provide a schedule for revising the generic technical specifications (GTS) and Bases so they do not contain any curly brackets. For curly brackets associated with DAC, modify the DCD to include an appropriately worded proposed COL Item for the COL applicant or holder, depending on the wording of the DAC; and for curly brackets associated with site specific information please modify the DCD to include an appropriately worded proposed COL Item for the COL applicant.

In response, the applicant revised its proposed COL Information Item 16.0-1 by dividing it into two parts, as stated in the following quotation from DCD Tier 2, Revision 5, Section 16.0.1:

16.0.1 COL Information

16.0-1-A COL Applicant Bracketed Items

COL applicants referencing the ESBWR DCD will replace the preliminary information provided in brackets (“[...]”), and annotated with “16.0-1-A” labels, with final plant specific information.

16.0-2-H COL Holder Bracketed Items

COL holders referencing the ESBWR DCD will replace the preliminary information provided in brackets (“[...]”), and annotated with “16.0-2-H” labels, with final plant specific information.

The introduction to DCD Tier 2, Chapter 16, Revision 5, contained one table for COL applicant items and another table for COL holder items. Each table assigned a unique identifier (labeled “COL Item”) to sets of related bracketed information, along with an associated reviewer’s note explaining how to properly provide the bracketed information. The applicant also annotated each instance of bracketed information with its identifier in the GTS and bases; this served as a cross reference to the appropriate COL item table. As a part of its RAI 16.2-164 response, the applicant included a justification for each COL holder item in the COL holder item table explaining why resolution of the item would be delayed until after issuance of the COL. The response to RAI 16.2-164 included the following six justifications for COL holder items:

1. “The plant specific pressure/temperature limits will be prepared using actual reactor pressure vessel materials properties that will be submitted by the COL holder once the reactor pressure vessel material properties are known, after shipment of the reactor pressure vessel.” The following COL holder item was associated with this justification:
 - 5.6.4-1 Pressure-temperature limits report listing of analytical methods used to determine the reactor coolant system (RCS) pressure and temperature limits

2. "ITAAC 2.2.2-7, #12 will require confirmation scram times and will be the appropriate test to determine the minimum scram accumulator pressure consistent with the ESBWR design (e.g., shorter core). The hydraulic conditions will provide a balance between meeting the maximum required scram times while at the same time assuring the drive does not insert so fast as to cause stress limits in the drive parts to be exceeded." The following COL holder items were associated with this justification:
 - 3.1.5-1 Minimum and nominal scram accumulator pressure
 - 3.9.5-1 Minimum scram accumulator pressure

3. "Determination of allowable values (AVs) for automatic instrumentation function trip settings is dependent on the instrumentation procured and final as-built information." The following COL holder items were associated with this justification:
 - 3.1.7-1 AV for standby liquid control (SLC) system accumulator level instrumentation function
 - 3.3.1.1-1 AVs for reactor protection system (RPS) instrumentation functions
 - 3.3.1.4-1 AVs for neutron monitoring system (NMS) instrumentation functions
 - 3.3.5.1-1 AVs for emergency core cooling system (ECCS) instrumentation functions
 - 3.3.5.3-1 AVs for isolation condenser system (ICS) instrumentation functions
 - 3.3.6.1-1 AVs for main steam isolation valve (MSIV) instrumentation functions
 - 3.3.6.3-1 AVs for isolation instrumentation functions
 - 3.3.7.1-1 AVs for the CR habitability area heating, ventilation, and air conditioning subsystem (CRHAVS) instrumentation functions
 - 3.3.8.1-1 AVs for diverse protection system (DPS) instrumentation functions
 - 3.7.1-1 AV for isolation condenser/passive containment cooling system (IC/PCCS) expansion pool-level instrumentation function
 - 3.7.2-2 AV for CRHAVS main control room (MCR) temperature instrumentation function
 - 3.7.6-2 AV for select control rod run-in/select rod insert (SCRRI/SRI) loss-of-feedwater-heating feedwater temperature instrumentation function

4. "Determination of startup range neutron monitor (SRNM) minimum count rate is dependent on the instrumentation procured and final as-built information." The following COL holder item was associated with this justification:
 - 3.3.1.6-1 Minimum SRNM count rate

5. "Requires design-specific information from battery manufacturer that is dependent on the battery procured." The following COL holder items were associated with this justification:
 - 3.8.1-1 Acceptance criteria for minimum duration of battery charger test
 - 3.8.1-2 Acceptance criteria for verification that battery is fully charged
 - 3.8.1-3 Use of a modified performance test to verify battery capacity

- 3.8.1-4 Battery cell parameters
 - 3.8.1-5 Battery margin for aging factor and state of charge uncertainty
 - 3.8.3-1 Acceptance criteria for verification that battery is fully charged
 - 3.8.3-2 Use of a modified performance test to verify battery capacity
 - 3.8.3-3 Battery cell parameters
 - 3.8.3-4 Battery margin for aging factor and state of charge uncertainty
6. "Filter differential pressure acceptance criterion is dependent on the specific filter train procured." The following COL holder item was associated with this justification:
- 5.5.13-1 Ventilation filter testing program (VFTP) requirement for the CRHAVS emergency filter unit (EFU) differential pressure acceptance criteria.

The STS and STS bases contain reviewer's notes stating conditions that a COL applicant (or Licensee) must satisfy in order to adopt a particular STS provision (e.g., incorporation of an NRC-approved methodology into a plant's licensing basis or a staff determination that a Licensee's probabilistic risk assessment program is of adequate quality). Satisfying such conditions is integral to completing COL Information Item 16.0-1, as described previously. However, in DCD Tier 2, Revision 5, the applicant relocated all GTS reviewer notes to DCD Tier 2, Chapter 16, Tables 16.0-1-A, "COL - Applicant Open Items," and 16.0-2-H, "COL - Holder Open Items." Because this presentation of reviewer notes is only an administrative difference between the GTS and the STS, the staff finds it acceptable.

In the GEH letter, dated February 24, 2009, regarding Interim Staff Guidance (ISG) DC/COL-ISG-8, "Necessary Content of Plant-Specific Technical Specifications," the applicant recharacterized each COL holder item as a COL applicant item. In accordance with the ISG, a COL applicant may address each of these items by providing the site-specific value, a useable bounding value, or an administrative control TS that requires determining the site-specific value using an NRC-approved methodology, with the value documented outside the PTS. Because the proposed GTS and bases no longer contain placeholders for the COL holder to address, RAI 16.2-164 is resolved.

RAI 16.0-3 The staff asked the applicant to list those STS generic changes (Technical Specifications Task Force [TSTF] travelers) that it was proposing for the GTS that are not included in STS Revision 3, including any proposed changes under review by the NRC. The staff also requested that the applicant explain any deviations from these travelers. In response, the applicant listed the following travelers (this report addresses any special considerations related to their adoption, where noted):

- TSTF-423-A, "Technical Specifications End States, NEDC-32988-A" (See discussion of RAI 16.0-7 in Section 16.2.0 of this report.) (The applicant withdrew this traveler from the GTS in DCD Revision 5.)
- TSTF-448-A, "Control Room Habitability" (See discussion of RAI 16.2-54 in Section 16.2.10 of this report.)
- TSTF-458-T, "Removing Restart of Shutdown Clock for Increasing Suppression Pool Temperature" (See Section 16.2.9 of this report.)

- TSTF-484-A, "Use of TS 3.10.1 for Scram Testing Activities" (See Sections 16.2.4 and 16.2.13 of this report.)
- TSTF-497-A, "Limit Inservice Testing Program SR 3.0.2 Application to Frequencies of 2 Years or Less" (See discussion of RAI 16.2-69 in Section 16.2.15 of this report.)
- TSTF-511-A, "Eliminate Working Hour Restrictions from TS 5.2.2 to Support Compliance with 10 CFR Part 26" (See Section 16.2.15 of this report.)

The following travelers have not been finalized, but upon NRC approval, the applicant stated that it may incorporate them in a future DCD revision. As of DCD Revision 7, the GTS had included provisions consistent with the current revisions of these travelers:

- TSTF-493, "Clarify Application of Setpoint Methodology for Limited Safety System Setting (LSSS) Functions," Revision 4 (See discussion of RAIs 16.2-25, 16.2-146, 16.2-149, and 16.2-156 in Section 16.2.6 of this report.) (Note that the NRC approved this traveler in its Federal Register Notice of Availability dated May 11, 2010, 75 FR 26294.)
- TSTF-500, "DC Electrical Rewrite," Revision 2 (See discussion of RAIs 16.2-55, 16.2-56, 16.2-57, 16.2-60, and 16.2-82 in Section 16.2.11 of this report.) (This traveler supersedes TSTF-360-A.)

Because the applicant provided a list of travelers that it had proposed to include in the GTS, RAI 16.0-3 is resolved.

The staff notes that the ESBWR GTS and bases are based on STS Revision 3 as revised by the incorporation of the following approved travelers; together this is referred to as STS Revision 3.1. The staff verified that these travelers, with the exceptions noted, are properly incorporated in the GTS and bases.

- TSTF-369-A, "Removal of Monthly Operating Report and Occupational Radiation Exposure Report"
- TSTF-372-A, "Addition of LCO 3.0.8, Inoperability of Snubbers" (not included in GTS)
- TSTF-400-A, "Clarify SR on Bypass of diesel generator (DG) Automatic Trips" (not applicable to ESBWR)
- TSTF-439-A, "Eliminate Second Completion Times Limiting Time From Discovery of Failure To Meet an LCO"
- TSTF-479-A, "Changes to reflect Revisions of 10 CFR 50.55a"
- TSTF-482-A, "Correct LCO 3.0.6 Bases"
- TSTF-485-A, "Correct Example 1.4-1"

Excluding TSTF-372-A is acceptable because including STS LCO 3.0.8 could potentially be less restrictive on unit operation in the event of an inoperable snubber. Excluding TSTF-400-A is acceptable because it only applies to a SR for safety-related DGs. The ESBWR GTS do not

specify this SR because 10 CFR 50.36(c)(2)(ii) does not require the ESBWR GTS to specify an LCO for the ESBWR DGs, which are not safety-related.

In DCD Tier 2, Revision 1, the applicant proposed adopting TSTF-451-T, “Correct Battery Monitoring and Maintenance Program and the Bases for STS SR 3.8.4.2,” Revision 0, which would have affected GTS SR 3.8.1.2 and SR 3.8.1.3, as well as GTS 5.5.10. (Note that this “T-traveler” had not previously been submitted to the NRC.) The applicant withdrew the changes based on this traveler when it subsequently proposed to use valve-regulated lead acid (VRLA) batteries instead of vented lead acid (VLA) batteries. This was appropriate because the changes to the STS proposed by this traveler apply only to VLA batteries. However, in DCD Revision 6, GEH withdrew its proposal to use VRLA batteries. The staff compared the revised requirements for GTS SR 3.8.1.2, and its bases, and GTS 5.5.10.b and determined that only GTS 5.5.10.b differed from the changes proposed by TSTF-451-T. GTS 5.5.10.b did not replace “electrolyte level below the minimum established design limit” with “electrolyte level below the top of the plates.” The staff finds the difference in GTS 5.5.10.b acceptable because the minimum established design limit is understood to be at or above the top of the plates. Since GTS SR 3.8.1.2 and its bases and GTS 5.5.10.b are consistent with Institute of Electrical and Electronics Engineers (IEEE) Standard 450-2002, “IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications,” the staff concludes that they are acceptable. However, since GEH did not explicitly propose to adopt TSTF-451-T in the GTS, the staff did not perform a detailed evaluation of TSTF-451-T. The staff’s evaluation of GEH’s response to RAI 16.2-89 in Section 16.2.15 of this report provides further evaluation of GTS 5.5.10.

RAI 16.0-5 The staff requested that GEH justify its decision to exclude the following BWR/6 STS requirements from the GTS by demonstrating that they do not satisfy the LCO-establishment requirements of 10 CFR 50.36(c)(2)(ii):

- STS Section 3.7 requirements for the service water system and ultimate heat sink (cooling towers), the CR fresh air system, and the CR heating ventilation and air conditioning system;
- STS Section 3.9 requirements for the reactor water cleanup/shutdown cooling system; and
- STS Section 5.5 requirements for the ventilation filter test program (VFTP), and the diesel generator fuel oil testing program.

In response, the applicant referred to the responses to RAIs 16.0-1, 16.2-52, and 16.2-74 and concluded that ESBWR active systems analogous to the BWR/6 systems addressed by the listed STS requirements satisfy none of the criteria of 10 CFR 50.36(c)(2)(ii). The staff determined that, based on the responses to RAI 16.0-1, GEH had adequately determined which of the listed STS requirements belong as equivalent requirements in the GTS; these are requirements for the control room habitability area (CRHA) heating, ventilation, and air conditioning (HVAC) subsystem (CRHAVS), and the VFTP. This determination resolves RAI 16.0-5. However, the staff sent GEH two supplements to RAI 16.0-5 focusing on the proposed passive cooling design for the CRHA after an accident. Section 16.2.10 of this report discusses these supplemental RAIs.

RAI 16.0-7 In DCD Tier 2, Revision 1, the applicant proposed GTS action requirements with modified end states based on TSTF-423-A, Revision 0. When a particular required action to restore compliance with the associated LCO is not met within the specified completion time, the associated action requirements for most LCOs have mandated placing the unit outside the

operational conditions during which the LCO is applicable (i.e., outside the specified applicability of the LCO - typically in Mode 5, cold shutdown). An LCO with a modified end state relaxation in the associated action requirements would only be required to place the unit in Mode 3, hot shutdown, or Mode 4, stable shutdown, rather than in Mode 5. In RAI 16.0-7, the staff asked the applicant to justify the proposed action requirements that specify modified end states. RAI 16.0-7 was being tracked as an open item in the SER with open items.

In response the applicant withdrew its proposal to adapt TSTF-423-A to the GTS and stated the following:

DCD Revision 5 will remove previously included “modified end state” Actions and corresponding Bases, including those applicable to TS 3.7.3. The Actions and associated Bases will be returned to appropriately match those in the BWR6 Standard Technical Specifications, NUREG-1434, Revision 3, without inclusion of TSTF-423-A end state changes.

The staff verified removal of all proposed modified end state changes in DCD Revision 5. Therefore, RAI 16.0-7 is resolved.

Sections 16.2.1 through 16.2.15 of this report compare the GTS with the STS and evaluate the differences.

16.2.1 ESBWR GTS Section 1.0, “Use and Application”

GTS Section 1.1, “Definitions,” defines terms that correspond to those given in the STS, with appropriate differences. The staff finds these defined terms and their definitions to be acceptable because they are consistent with ESBWR design features and the STS.

The proposed definition of “dose equivalent I-131” differs from the STS definition by listing different source documents for the thyroid dose conversion factors used to calculate the Dose equivalent I-131. The dose conversion factors from these source documents are acceptable because they are consistent with the ESBWR dose analysis, which uses the total effective dose equivalent methodology, and Regulatory Guide (RG) 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.” GTS 3.4.3, “RCS Specific Activity,” places a limit on dose equivalent I-131, in accordance with Criterion 2 of 10 CFR 50.36(c)(2)(ii). This limit will ensure that the doses resulting from a DBA, such as a main steam line break (MSLB), will be within the bounding values of the ESBWR accident analysis. Therefore, specifying different source documents for the thyroid dose conversion factors in the definition for dose equivalent I-131 is appropriate and is acceptable as proposed.

GTS Section 1.1 omits STS definitions for “average planar linear heat generation rate,” “end-of-cycle recirculation pump trip system response time,” and “maximum fraction of limiting power density.” The ESBWR GTS do not use these definitions. Therefore, their omission is acceptable.

RAI 16.2-11 The staff requested that the applicant explain why it had omitted the definition for “physics test” from GTS Section 1.1. In Part 1 of its response, the applicant justified its decision to exclude the term “physics test” in the GTS by explaining that the performance of physics tests for the ESBWR will not require an exception to the normal GTS requirements because of ESBWR design characteristics. The prevalent design characteristics arise because the ESBWR uses natural circulation for core flow instead of relying on forced flow using recirculation pumps.

Therefore, omission of the term “physics test” from the GTS is acceptable, and Part 1 of RAI 16.2-11 is resolved. Section 16.2.5 of this report discusses Part 2 of the applicant’s response to RAI 16.2-11 and the related RAI 16.2-24.

RAI 16.2-12 The staff requested that the applicant explain the difference between the proposed definition of “shutdown margin” (SDM) and the STS definition of SDM. In response, the applicant explained that specifying that the SDM determination assumes that “the control rod or control rod pair of highest reactivity worth” is fully withdrawn, instead of withdrawal of just the highest worth control rod, reflects an ESBWR design difference. The ESBWR uses fine motion control rod drives (FMCRDs) that, except for one control rod, group control rods in pairs. Therefore, the staff finds the difference in the SDM definition to be acceptable because of this difference in design. On the basis of this information, therefore, RAI 16.2-12 is resolved.

The ESBWR GTS contain an additional definition (i.e., ICS response time), which reflects the ICS design feature.

In GTS Table 1.1-1, “Modes,” the STS Mode 3 definition is replaced with new ESBWR definitions for Modes 3 and 4. The new Mode 3, “hot shutdown,” is defined as the combination of (1) reactor mode switch in the shutdown position, (2) average reactor coolant temperature greater than 215.6 degrees Celsius (C) (420 degrees Fahrenheit [F]), and (3) all reactor vessel head closure bolts fully tensioned. This definition narrows the average reactor coolant temperature range of the STS Mode 3 definition. The new definition of Mode 4, “stable shutdown,” captures the remaining part of the temperature range of the STS Mode 3 definition. The STS definitions for Mode 4, “cold shutdown,” and Mode 5, “refueling,” are adopted without change, but are renumbered Mode 5 and Mode 6, respectively, in the ESBWR GTS. The new Mode 4 is defined as the combination of (1) reactor mode switch in the shutdown position, (2) average reactor coolant temperature less than or equal to 215.6 degrees C (420 degrees F) and greater than 93.3 degrees C (200 degrees F), and (3) all reactor vessel head closure bolts fully tensioned. Use of this definition reflects the NRC’s conclusion that plant temperatures below 215.6 degrees C (420 degrees F) are an acceptable stable, safe-shutdown condition in which the plant may be placed in the event that an LCO is not met under certain conditions, such as those addressed by TSTF-423-A. However, as discussed in Section 16.2.0 of this report, under RAI 16.0-7, the applicant withdrew its proposal to adapt TSTF-423-A to the GTS and adopt modified end states. Nevertheless, the revised mode definitions are not affected and will facilitate future adoption of modified end states by COL applicants or Licensees referencing the ESBWR GTS.

ESBWR GTS Section 1.2, “Logical Connectors,” which defines the use of “OR” and “AND” in GTS Sections 2.0, 3.0, and 3.1 through 3.10, is identical to the STS and is acceptable.

ESBWR GTS Section 1.3, “Completion Times,” which defines the rules for applying required action completion times in GTS Sections 2.0, 3.0, and 3.1 through 3.10, differs from the STS to account for the differences between the ESBWR and the BWR/6 designs. For example, no safety systems in the ESBWR design rely on pumps, so GEH revised the STS Section 1.3 examples that discuss inoperable pumps to discuss inoperable valves in the ESBWR GTS. In addition, where appropriate, Mode 5 is used in place of Mode 4. Therefore, GTS Section 1.3 is acceptable.

RAI 16.2-13 The staff requested that the applicant consider adding to GTS Section 1.3 an example to illustrate the use of the modified end state of Mode 3 for an LCO that is applicable in Modes 1, 2, 3, and 4, and, specifically, to make clear the implementation guidance (TSTF-IG-

05-02) for the related TSTF-423-A, which limits the unit's stay in the modified end state to 7 days. In RAI 16.0-7, the staff had requested that GEH provide additional ESBWR-specific justification and implementation guidance. However, as discussed in Section 16.2.0 under RAI 16.0-7, the applicant withdrew its proposal to adapt TSTF-423-A to the GTS and adopt modified end states provisions, and did not submit the requested justification and implementation guidance. The staff evaluated the applicant's response to RAI 16.2-13, which stated that a new completion time example is not needed to ensure correct application of modified end state action requirements. In this evaluation, the staff assumed that an acceptable justification and implementation guidance had been provided. As discussed in Section 16.2.3 of this report, the staff believes that incorporating TSTF-423-A into the ESBWR GTS and bases would preclude unintentional misuse of modified end state provisions and ensure that an acceptable level of safety is maintained. Since the GTS bases would direct adherence to the established NRC-approved implementation guidance when utilizing NRC-approved modified end state TS action requirements, the staff concluded that no additional clarification of the guidance, such as an example in GTS Section 1.3, is warranted. Therefore, the staff finds the applicant's response to RAI 16.2-13 acceptable and considers this issue resolved.

ESBWR GTS Section 1.4, "Frequency," which defines the rules for applying frequencies (test intervals) specified for performing SRs, is consistent with the STS, except for the use of the ESBWR GTS Mode 3 and Mode 4 definitions in place of the STS Mode 3 definition, and is therefore acceptable.

Based on the above, the staff finds GTS Section 1.0 acceptable.

16.2.2 ESBWR GTS Section 2.0, "Safety Limits"

Section 2.0 of the ESBWR GTS outlines the safety limit (SL) specifications, which are mostly consistent with the STS. The staff requested additional information to complete its review, as described below.

RAI 16.2-14 and RAI 16.2-52 (Related to RAI 15.0-16) The staff asked the applicant in RAI 16.2-14 to justify the omission of the minimum critical power ratio (MCPR) and its limiting numerical value in the statement of reactor core SL 2.1.1.2. Instead, the applicant had proposed stating the SL with the following condition: "Greater than 99.9% of the fuel rods in the core would be expected to avoid boiling transition." The staff considers that this condition is a criterion for an SL but is not itself an SL. The SL in this case should be a parameter, such as the MCPR or fuel rod peak centerline temperature, with a numerical value provided in brackets consistent with the BWR/6 STS SL 2.1.1.2. The staff also asked the applicant to explain the discrepancy between the bases for the proposed SL 2.1.1.2, which refers to the MCPR, and SL 2.1.1.2, which does not. RAI 16.2-14 was being tracked as an open item in the SER with open items.

In RAI 16.2-52, the staff referred to RAI 15.0-16 and requested that the applicant provide a basis for the proposed safety limit for minimum critical power ratio (SLMCPR) similar to that provided in the BWR/6 STS bases. RAI 16.2-52 and RAI 15.0-16 were being tracked as open items in the SER with open items.

In response to RAI 16.2-14, the applicant stated that it would address this comment in its response to RAI 15.0-16. In RAI 15.0-16, the staff requested that the applicant revise SL 2.1.1.2 to specify an SLMCPR value and stated that the agency's policy is to include a numerical value for the SLMCPR.

In response to RAI 15.0-16, the applicant stated that it had changed the bases for SL 2.1.1.2, LCO 3.2.2, LCO 3.3.1.1, LCO 3.3.1.4, LCO 3.3.2.1, and LCO 3.7.3 by replacing “MCPR” and “MCPR safety limit” with “fuel cladding integrity safety limit (FCISL).” The applicant also revised the bases for LCO 3.3.2.1 by replacing “operating and safety limit MCPR and LHGR” with “operating limit MCPR, fuel cladding integrity safety limit and LHGR.” The applicant incorporated these bases changes into DCD Revision 2. However, GEH did not propose a numerical value for the SLMCPR.

In response to RAI 16.2-52, the applicant referred to its initial response to RAI 15.0-16. However, in RAI 15.0-16 S01, the staff stated it had found the response unacceptable and that GEH should include a numerical value for the SLMCPR as a TS SL as is done in the BWR/6 STS. In response to RAI 15.0-16 S01, the applicant stated that “the TRACG methodology directly establishes an Operating Limit Minimum Critical Power Ratio (OLMCPR), such that less than 0.1 percent of the fuel rods are expected to experience boiling transition, but does not establish a lower bound on the steady-state MCPR.” In addition, GEH stated the following position:

Although using the ESBWR TRACG FCISL Reactor Core Safety Limit terminology ensures protection of the fuel cladding for AOOs, it is recognized that a separate lower bound on the steady-state MCPR (i.e., SLMCPR) protects the fuel cladding when the MCPR is not within its LCO specification. A potential violation of the Reactor Core Safety Limit would only occur if the newly defined ESBWR SLMCPR is violated during steady-state operations, or if an AOO occurs when the MCPR is not within its LCO specification. For both of these situations, the process variable MCPR could be used. GEH proposes the following revised response to the original RAI 15.0-16 response.

In the revised response, GEH proposed that the ESBWR SLMCPR be included in the GTS as determined by the ODYN methodology (NEDO-24154-A, Volumes 1 and 2, dated August 1986; NEDE-24154-P-A, Volume 3, dated August 1988, and NEDC-24154-P-A, Supplement 1, Volume 4, “Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors,” dated February 2000). Chapter 15 of this report provides further evaluation of the details of the proposed SLMCPR. The applicant proposed the following changes to GTS SL 2.1.1.2 and the bases for GTS 2.1.1, “Reactor Core Safety Limits,” and GTS 3.3.2.1, “Control Rod Block Instrumentation”:

- The applicant revised SL 2.1.1.2 to state the following:
 - “With the reactor steam dome pressure ≥ 5.412 MPaG (785 psig): Greater than 99.9% of the fuel rods in the core would be expected to avoid boiling transition. All MCPRs shall be greater than or equal to 1.18 during steady-state operation.”
- The applicant revised the bases for GTS Section 2.1.1 as follows:
 - The following sentence was added to the end of the first paragraph in the applicable safety analysis section: “The Safety Limit MCPR (SLMCPR) is a lower bound on the steady-state MCPR that ensures greater than 99.9% of the fuel rods in the core would be expected to avoid boiling transition.”
 - The title for the discussion of SL 2.1.1.2, in the applicable safety analysis section, was changed from “FCISL” to “FCISL and SLMCPR.”

- The following sentence was added to the end of the discussion of SL 2.1.1.2 in the applicable safety analysis section: “The Safety Limit MCPR (SLMCPR) is a lower bound on the steady-state MCPR. Details of the SLMCPR calculation process are given in Reference 5.” In DCD Revision 7, Reference 5 of DCD Revision 4 became Reference 2: NEDC-33237P, GE14 for ESBWR - Critical Power Correlation, Uncertainty, and OLMCPR Development, Revision 4. See below discussion of RAI 16.2-191.
- The applicant revised the bases for GTS Section 3.3.2.1 as follows:
 - The phrase, “the Fuel Cladding Integrity Safety Limit (FCISL),” was replaced with the phrase, “the Safety Limit MCPR (SLMCPR),” in the second sentence of the second paragraph of the background section.
 - The acronym “FCISL” was replaced with the acronym “SLMCPR” in the first sentence of the first paragraph of the applicable safety analyses, LCO, and applicability section.

The staff finds these changes appropriate because they are consistent with its position that the ESBWR TS should contain a numerical value for the SLMCPR. The staff verified that DCD Revision 5 incorporated these changes. Based on these changes, RAIs 15.0-16, 16.2-14 and 16.2-52 are resolved.

RAI 16.2-159 In Revision 4 of the GTS, GEH changed the RCS pressure SL (i.e., SL 2.1.2) from the following statement: “Reactor steam dome pressure shall be $\leq \{9.211\}$ MPaG ($\{1336\}$ psig),” which is consistent with the STS presentation, to the following statement: “Reactor vessel bottom pressure shall be ≤ 9.481 MPaG (1375 psig).” GEH made this revision to ensure that the RCS pressure SL was consistent with the SL intent and the overpressure analysis acceptance criteria used in DCD Tier 2, Section 5.2.2.3.3. In RAI 16.2-159, the staff requested the applicant to provide additional justification for its decision to deviate from the STS. In response, GEH explained that the proposed presentation “eliminates a potential ambiguity in the application of the safety limit that could occur when the SL is specified for a location other than where the peak pressure would occur,” as is done in the STS. However, “application of the safety limit” in terms of vessel bottom pressure will always require evaluation of the monitored parameter - the steam dome pressure - to determine the maximum pressure reached at the reactor vessel bottom during an RCS pressure transient. The reactor vessel bottom pressure should be determined by adding to the reactor steam dome pressure the static pressure corresponding to the reactor vessel water level and density. DCD Tier 2, Revision 4, Table 15.2-5, lists for each analyzed event the calculated maximum reactor steam dome pressure and the calculated maximum reactor vessel bottom pressure. This table shows that the difference between these calculated pressures varies between 0.13 MPaG (19 psig) and 0.15 MPaG (22 psig), depending on the event. In the case of a pressure transient approaching the SL value, the Licensee must determine whether the RCS pressure SL was exceeded. The staff expects the Licensee to determine the peak reactor vessel bottom pressure, which occurs during the transient, by adding a conservative pressure difference to the maximum observed reactor steam dome pressure. A conservative pressure difference would derive from reactor vessel thermal-hydraulic conditions (e.g., coolant level, density, flow, temperature) that are bounding to the conditions observed during the transient.

The staff also requested that the applicant revise the GTS bases to be consistent with the level of detail (regarding the specific RPS instrumentation function) in the discussion of the applicable safety analyses (ASA) found in the STS SL 2.1.2 bases. The applicant justified the proposed level of detail in the GTS bases as follows:

As indicated in DCD, Tier 2, Section 5.2.2, "Overpressure Protection," and Section 5.2.2.3.1, "Method of Analysis," the RCS overpressure analyses assume that peak pressure in the RPV during a plant transient is limited by the combination of the safety valves and a reactor trip. However, to allow for a potential failure in the RPS, the analysis assumes that the reactor trip is initiated by the second safety-grade signal from the RPS. DCD Section 5.2.2.3.1 indicates that the results of the overpressure analyses are acceptable when the reactor trip is [initiated] by main steam isolation valve position, neutron monitoring system flux, or RPS. The sequence in which these reactor trip signals are generated will vary depending on the transient. Therefore, DCD, Tier 2, Chapter 16B, Section B 2.1.2, uses the phrase "Reactor Protection System Scram settings" rather than stating that a specific reactor trip function is needed to protect the reactor pressure vessel safety limit.

By expressing the RCS pressure SL in terms of the "reactor vessel bottom pressure," the applicant has improved the presentation of the proposed GTS SL 2.1.2 and the ASA discussion in the associated bases when compared to the STS because this parameter directly corresponds to the limiting location in the RCS. GTS SL 2.1.2 and the associated bases are acceptable because (1) the ASA discussion in the bases explicitly states that the reactor vessel bottom is "the lowest elevation of the RCS," (2) the peak pressure reached at the reactor vessel bottom during a pressure transient may be readily determined, and (3) the RPS function that actuates to scram the reactor, which limits the rise in reactor vessel pressure, varies depending upon the event causing the pressure transient. Therefore, RAI 16.2-159 is resolved.

RAI 16.2-191 The staff asked that GEH revise the "Applicable Safety Analyses (ASA)" and "References" sections of the bases for GTS 2.1.1, regarding the reactor core SL of fuel cladding integrity, SL 2.1.1.1, by removing the reference to topical report NEDC-32851P-A, "GEXL14 Correlation for GE14 Fuel," Revision 5, for the critical power correlation, GE14. Although this reference is approved for currently operating BWRs that use 12-foot GE14 fuel, it does not directly apply to the ESBWR GE14E fuel. The staff asked GEH to replace this reference in the "ASA" section of the bases with the ESBWR-specific critical power correlation reference, topical report NEDC-33237P, "GE14 for ESBWR - Critical Power Correlation, Uncertainty, and OLMCPR Development," Revision 4. The "References" section of the bases for GTS 2.1.1 already lists NEDC-33237P as Reference 6. In response, GEH stated it would make the requested changes to the bases for GTS 2.1.1. In addition, GEH also stated it would remove NEDC-32851P-A from DCD Tier 2, Table 1.6-1, "Referenced GE / GEH Reports." The staff reviewed the markup of the affected pages in the DCD, which GEH included in its response letter, and found them to be acceptable. However, the bases for SL 2.1.1 in DCD Tier 2, Revision 9, references Revision 5 instead of Revision 4 of NEDC-33237P-A. Since Revision 5 is the NRC-approved version of the topical report, this variation from the applicant's response to RAI 16.2-191 is acceptable. Therefore, the response is acceptable and RAI 16.2-191 is resolved.

Based on the resolution of the staff's RAIs and the consistency with the STS, the staff finds that GTS Section 2.0 and bases are acceptable.

16.2.3 ESBWR GTS Section 3.0, "Limiting Condition for Operation Applicability and Surveillance Requirement Applicability"

Section 3.0 of the ESBWR GTS governs the general application of the LCOs and SRs. The specifications provided in Section 3.0, which correspond to the STS (LCOs 3.0.1 through 3.0.7

and SRs 3.0.1 through 3.0.4), are acceptable to the staff because they are consistent with the STS. In addition, the following RAIs have been successfully resolved.

RAIs 16.0-4 and 16.2-16 The difference between the ESBWR GTS statement of LCO 3.0.3 and the STS accommodates the introduction of the new definition of Mode 4 (stable shutdown). The staff requested the applicant, in RAI 16.2-16, to specify definite completion times in LCO 3.0.3 for reaching Mode 4 and Mode 5 (cold shutdown), consistent with the STS. In addition, the staff asked the applicant in RAI 16.0-4 to justify the proposed completion times for reaching lower modes of operation or other specified conditions in LCO 3.0.3 and all specifications with shutdown action requirements. In response, the applicant proposed that LCO 3.0.3 specify completion times of 25 hours to be in Mode 4 and 37 hours to be in Mode 5 and subsequently incorporated these changes to LCO 3.0.3 in DCD Tier 2, Revision 1, Chapter 16. These completion times, which are consistent with the STS, are acceptable because they are consistent with the capabilities of the ESBWR design and ensure that the required conditions can be reached from full-power conditions in an orderly manner without challenging safety systems. The completion times for shutdown actions in other specifications are acceptable because they are consistent with those specified for LCO 3.0.3. Therefore, RAIs 16.0-4 and 16.2-16 are resolved.

RAI 16.2-15 The staff requested that the applicant describe how modified end states (usually Mode 3 in LCOs with required actions that do not specify exiting the applicability of the LCO) may affect implementation of LCOs 3.0.3 and 3.0.4 and SRs 3.0.1 and 3.0.4. In response, the applicant addressed each of these specifications. However, as discussed in Section 16.2.0 of this report under the evaluation of the response to RAI 16.0-7, the applicant withdrew its proposal to adapt TSTF-423-A to the GTS and adopt modified end states. Therefore, RAI 16.2-15 is resolved.

RAI 16.2-17 The staff requested that the applicant discuss why it had not proposed an LCO similar to AP1000 LCO 3.0.8 that would apply during shutdown conditions (i.e., ESBWR GTS Modes 5 and 6) when the action requirements of an LCO are not met and no other action is specified or when none of the action requirements of an LCO address the plant condition. Such an LCO would function in the same way as LCO 3.0.3, except that it would not apply during operating modes (Modes 1, 2, 3, and 4) but would apply during cold shutdown and refueling. In response, the applicant stated that the STS have no such requirement and that the action requirements of the ESBWR specifications that are applicable during Modes 5 and 6, together with LCO 3.0.2, are equivalent to those provided by the first of the two AP1000 LCO 3.0.8 action requirements (i.e., 3.0.8.a, which requires action to be initiated to restore inoperable equipment to operable status), so a separate GTS requirement is unnecessary. The applicant also stated that the provisions of 10 CFR 50.65(a)(4) adequately address the second AP1000 LCO 3.0.8 action requirement (3.0.8.b, which requires action to be initiated to monitor safety system shutdown monitoring tree parameters), making it unnecessary as a TS requirement. The STS intentionally exclude requirements that are redundant to or duplicative of other STS requirements or regulations. Therefore, based on the preceding discussion, RAI 16.2-17 is resolved.

Based on the above, GTS Section 3.0 and bases are acceptable.

16.2.4 ESBWR GTS Section 3.1, “Reactivity Control Systems”

Section 3.1 of the ESBWR GTS governs reactivity control systems. The following specifications in Section 3.1 that correspond to those given in STS 3.1.1 through 3.1.7 are acceptable to the staff because they are consistent with the STS:

- 3.1.1, “Shutdown Margin (SDM)”
- 3.1.2, “Reactivity Anomalies”
- 3.1.3, “Control Rod Operability”
- 3.1.4, “Control Rod Scram Times”
- 3.1.5, “Control Rod Scram Accumulators”
- 3.1.6, “Rod Pattern Control”
- 3.1.7, “Standby Liquid Control (SLC) System”

The ESBWR design does not include scram discharge volumes (SDVs), so a GTS based on STS 3.1.8, “SDV Vent and Drain Valves,” was not adopted. In addition, the following RAIs have been successfully resolved.

RAI 16.2-18 The staff requested that the applicant justify its decision not to include action requirements equivalent to STS 3.1.1, Required Actions D.4 and E.5, which both require initiating action to restore isolation capability in each required (i.e., secondary containment) penetration flow path that is not isolated within 1 hour of discovery that the SDM is outside the limits in Mode 4 and Mode 5, respectively. In response, the applicant explained that ESBWR GTS 3.1.1 contains action requirements implicitly equivalent to these STS action requirements and explicitly equivalent to STS 3.1.1, Required Actions D.2 and E.3, both of which require initiating action to restore secondary containment to operable status. In the ESBWR GTS, the reactor building specification is equivalent to both the STS secondary containment specification and the secondary containment isolation valve specification, since the ESBWR design does not have a secondary containment equivalent to that of the BWR/6 design. An operable reactor building requires isolation capability of all penetration flow paths. In DCD Tier 2, Revision 5, GEH made additional changes to Actions D and E. Upon discovery that the SDM is not within limits in Mode 5 and 6, GTS 3.1.1, Actions D and E, respectively, both call for immediately initiating action to either (1) isolate the reactor building refueling and pool area heating, ventilation, and air conditioning (HVAC) subsystem (REPAVS) and contaminated area HVAC subsystem (CONAVS) areas or (2) establish reactor building REPAVS and CONAVS area automatic isolation capability on respective exhaust high radiation signals. These are appropriate actions for SDM not within limits in Modes 5 and 6 and are consistent with the STS actions to restore secondary containment operability. Therefore, RAI 16.2-18 is resolved.

RAI 16.2-19 The staff requested that the applicant remove the word “each” from the Completion Time for Required Action A.3 of GTS 3.1.3, “Control Rod Operability,” for the condition of “one withdrawn control rod stuck” because the action note allows separate condition entry for each control rod. Thus, the word “each” in the completion time of “24 hours from ‘each’ discovery of Condition A concurrent with thermal power greater than the low power setpoint” is unnecessary and potentially confusing. In response, the applicant stated that it would remove the word “each.” DCD Tier 2, Revision 2, Chapter 16 includes this change. Therefore, RAI 16.2-19 is resolved.

RAI 16.2-20 The staff asked the applicant to explain why GTS SR 3.1.3.2 and SR 3.1.3.3 specify moving the control rod two notches instead of one notch, as specified in the STS. In response, the applicant stated that two notches for the ESBWR FMCRD is approximately the

same distance as one notch for the typical BWR/6 control rod drive (CRD) and that insertion by at least two notches is compatible with the requirements of the ganged withdrawal sequence restrictions (GTS 3.1.6) and the rod control and information system (GTS 3.3.2.1). Therefore, SR 3.1.3.2 and SR 3.1.3.3 are acceptable, and RAI 16.2-20 is resolved.

RAI 16.2-21 The staff requested that the applicant address the omission of the phrase “control rod pair” in the GTS bases’ discussion of the note for the SRs of GTS 3.1.4. The note states, “During single or control rod pair scram time Surveillances, the CRD pumps shall be isolated from the associated scram accumulator.” In response, the applicant stated that it would correct this omission with the following sentences:

All four SRs of this LCO are modified by a Note stating that during a single control rod or control rod pair scram time Surveillance, the CRD pumps shall be isolated from the associated scram accumulator. With the CRD pump isolated (i.e., charging valve closed) the influence of the CRD pump head does not affect the single control rod or control rod pair scram times.

DCD Tier 2, Revision 2, Chapter 16B includes this change. Therefore, RAI 16.2-21 is resolved.

RAIs 16.2-22 and 16.2-91 In RAI 16.2-22, the staff requested that the applicant add a discussion in the bases for GTS Table 3.1.4-1, “Control Rod Scram Times,” Footnote (c), which stated, “For reactor steam dome pressure < [6.550 MPaG (950 psig)], only the [60] percent insertion scram time limit applies.” Footnote (c) applied only to the table column for a reactor steam dome pressure of 0 MPaG (0 psig). In response the applicant stated that the “insertion time limit at 0 psig is not necessary for the ESBWR” and that it would eliminate the 0 psig column and the associated note from Table 3.1.4-1, making the table and notes consistent with STS Table 3.1.4-1. DCD Tier 2, Revision 2, Chapter 16B includes this change. In response to RAI 16.2-22 S01, the applicant explained that Footnote (b) to Table 3.1.4-1 applies when performing scram insertion time testing when the reactor is depressurized (0 MPaG [0 psig]) up to a reactor vessel bottom pressure of 7.48 MPaG (1,085 psig). Removing Footnote (c) in response to the initial question did not eliminate the requirement for a test at 0 MPaG (0 psig). In addition, the scram times identified in the table match those stated in the accident analysis descriptions in DCD Tier 2, Chapter 15. In RAI 16.2-91, the staff asked the applicant to explain the reactor pressure vessel (RPV) pressures associated with the identical scram time criteria in GTS Table 3.1.4-1 and DCD Tier 2, Tables 15.2-2 and 15.2-3. In response, GEH stated that it would verify that the RPV steam dome pressures in the GTS table are equivalent to the RPV bottom head pressures in the tables in DCD Chapter 15, once the pressure values were determined. DCD Tier 2, Revision 5, Tables 15.2-2 and 15.2-3, cite final pressures of 7.48 MPaG (1,085 psig) and 8.62 MPaG (1,250 psig) for the bottom head and 7.34 MPaG (1,065 psig) and 8.46 MPaG (1,227 psig) for the steam dome, respectively. The pressure differences between the bottom head and the steam dome of 0.14 MPa (20 psi) and 0.16 MPa (23 psi) appear reasonable, if the water is assumed to be saturated and if vessel water level is assumed to be the normal level of 20.72 meters (m) (68 feet [ft]) above the vessel bottom. Because the pressures in the tables are equivalent and the scram time criteria match the values assumed in the accident analyses, the staff concludes that the proposed GTS Table 3.1.4-1 is acceptable. Therefore RAIs 16.2-22 and 16.2-91 are resolved.

RAI 16.2-75 The staff issued RAI 16.2-75, requesting that the applicant add DCD references to the bases for GTS 3.1.1, “Shutdown Margin.” In RAI 16.2-75 S01 the staff noted that the “ASA” section of the bases for GTS 3.1.1 presents the control rod withdrawal (or removal) error (RWE) during refueling as the event basis for the LCO on SDM. The staff asked the applicant to

confirm whether RWE during refueling is more limiting than RWE at startup or low power. If RWE at startup or low power is more limiting, then the reference in the GTS bases should be changed to RWE during startup; that is, the applicant should change the DCD reference from Section 15.3.7 to Section 15.3.8. (See Section 15.3 of this report for a discussion of RAI 15.3-33 regarding analysis of the RWE event during power operation.) RAI 16.2-75 S01 was being tracked as an open item in the SER with open items. In response, the applicant explained that RWE during refueling is more limiting than RWE during startup and power operation because only the analysis of RWE during refueling explicitly credits a subcriticality margin. Therefore, RAI 16.2-75 is resolved.

RAI 16.2-90 The staff requested that the applicant include in the bases for GTS 3.1.3 a discussion of the indications of a stuck control rod. In response, the applicant added the following statements to the "Actions" section of the bases for GTS 3.1.3, Action A: "A control rod is stuck if it will not insert by either fine motion control rod drive (FMCRD) motor torque or hydraulic scram pressure. A control rod is not made inoperable by a failure of the FMCRD motor if the rod is capable of hydraulic scram." Therefore, RAI 16.2-90 is resolved.

RAI 16.2-93 The staff asked the applicant why it had not proposed to include STS SR 3.1.7.8 to verify the required flow through one SLC subsystem. In response, GEH stated that it had added SR 3.1.7.9, "Verify flow through one flow path on one SLC train from accumulator into reactor pressure vessel," with a frequency of 24 months on a staggered test basis for each of the four flow paths - two flow paths per train. Since accumulators pressurized with nitrogen provide the driving force for SLC system flow, specifying a minimum flow rate is not a meaningful surveillance acceptance criterion. Once the capability to deliver the required volume in the specified time for each flow path is demonstrated during preoperational testing of the SLC system, it is sufficient to periodically verify that each flow path is not obstructed and that the accumulators contain the required volume of boric acid solution at the specified pressure. Based on the addition of this SR, RAI 16.2-93 is resolved.

RAI 16.2-104 The staff requested that GEH revise SR 3.1.3.5, "Verify each control rod does not go to the withdrawn overtravel position," to include the frequency from the equivalent BWR/6 STS SR 3.1.3.5 of "Each time the control rod is withdrawn to 'full out' position." In response, GEH stated that it would revise the frequency to include this frequency in addition to the frequency of "Prior to declaring control rod OPERABLE after work on control rod or CRD System that could affect coupling." However, DCD Revision 3 did not reflect this change. In the list of changes between Revision 2 and Revision 3, Item 14 states that the "coupling check when the rod is full withdrawn is not required because the ESBWR design includes redundant instrumentation that provide immediate indication of an uncoupled rod." DCD Tier 2, Section 7.7.2.1.2 states that there are "dual redundant measurements of the absolute rod position during normal FMCRD conditions." The bases for SR 3.1.3.5 also state that the retained frequency is acceptable because of the mechanical integrity of the bayonet coupling design of the FMCRDs. For these reasons, the omission of the frequency of "Each time the control rod is withdrawn to 'full out' position" is acceptable. Therefore, RAI 16.2-104 is resolved.

RAI 16.2-109 The staff requested that GEH modify the GTS bases to be consistent with the resolution of RAI 4.6-23 regarding the treatment of the control rod drop accident (CRDA) in the ESBWR design, as described in the DCD. The staff noted that the bases for GTS 3.1.1 and GTS 3.1.3 do not discuss the CRDA, which is discussed in the STS bases. Furthermore, the bases for GTS 3.1.3, Required Actions A.1, A.2, A.3, and A.4, and GTS 3.1.6, 3.10.7, and 3.10.8 discuss the RWE analysis in place of the CRDA analysis, which is discussed in the STS bases. RAI 16.2-109 was being tracked as an open item in the SER with open items. In

response, GEH stated that the GTS bases do not discuss the CRDA because it is not credible based on the design of the FMCRD and control rods used in the ESBWR. Since RAI 4.6-23 is resolved as described in Section 4.3 of this report, the CRDA is not deemed credible and the RWE event is the correct reference, the above differences from the STS bases are acceptable. Therefore, RAI 16.2-109 is resolved.

RAI 16.2-169 The staff asked the applicant to revise Action D of GTS 3.1.7 to require a unit shutdown. As written, Actions Condition D could mean that at least one accumulator is unavailable for ECCS injection. Since both accumulator volumes are necessary for successful mitigation of a loss-of-coolant accident (LOCA), this condition represents a loss of ECCS function; therefore, shutdown actions should be specified rather than an 8-hour completion time for restoring SLC system operability. In response, GEH combined Conditions D and E and deleted the action to restore SLC system operability in 8 hours. New Condition D corresponds to both a loss of capability to inject by one or both SLC trains and a failure to restore boron concentration to within limits in 72 hours (Action A), restore injection squib valve flow paths to operable status in 7 days (Action B), or restore accumulator isolation valves to operable status in 7 days (Action C). Action D requires a unit shutdown to Mode 5 in 36 hours, which is appropriate for the stated conditions. The applicant made appropriate conforming changes to the "Actions" section of the bases for GTS 3.1.7. With these changes, RAI 16.2-169 is resolved.

Based on the above evaluation and resolution of the RAIs, the staff concludes that GTS Section 3.1 and bases are acceptable.

16.2.5 ESBWR GTS Section 3.2, "Power Distribution Limits"

Section 3.2 of the ESBWR GTS governs core power distribution limits. Section 3.2 includes GTS 3.2.1, "Linear Heat Generation Rate (LHGR)," and GTS 3.2.2, "Minimum Critical Power Ratio (MCPR)," which correspond to STS 3.2.3 and STS 3.2.2, respectively. The staff finds these specifications acceptable based on their consistency with the STS and the resolution of the following RAIs.

RAIs 16.2-11 and 16.2-24 In RAI 16.2-24, the staff asked the applicant to explain why the ESBWR GTS do not include STS 3.2.1, "Average Planar Linear Heat Generation Rate (APLHGR)," and STS 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoints." In response, the applicant stated that the limits on "average planar linear heat generation rate" (APLHGR) are not necessary for the ESBWR to meet the requirements of 10 CFR 50.46, regarding the limits for peak clad temperature and oxidation during a DBA LOCA because the RPV water level never falls below the top of the core during any ESBWR DBA. Based on this analysis result, the staff finds that the omission of TS for APLHGR and the APLHGR definition are acceptable. The applicant stated that it would address omission of STS 3.2.4 in its response to RAI 16.2-11.

RAI 16.2-11 The staff asked the applicant to justify its exclusion of the physics test definition of "maximum fraction of limiting power density" (MFLPD) from GTS Section 1.1. In Part 2 of its response to RAI 16.2-11, the applicant stated that STS Section 1.1 includes a definition for MFLPD and refers to MFLPD in STS 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoints (Optional)." In the STS, Specification 3.2.4 is optional for plants that must adjust either the flow-biased scram setpoints or APRM gain or limit power level to protect against the possibility of exceeding the thermal limits due to local power peaking at off-rated conditions. Similar to the approach used in the STS, the ESBWR core will maintain the required thermal limits in the Core Operating Limits Report (COLR), which will ensure that required thermal limits

are met without the need for a TS equivalent to STS 3.2.4. Therefore, omission of the MFLPD definition and an LCO for APRM gain and setpoints is acceptable. Based on this, as well as the discussion in Part 1 of the applicant's response to RAI 16.2-11, as described in Section 16.2.1 of this report, RAIs 16.2-11 and 16.2-24 are resolved.

RAI 16.2-33 The staff requested that the applicant review the response to RAI 16.0-1 (which provided a systematic evaluation of the information in the DCD against the requirements of 10 CFR 50.36(c)(2)(ii)), considering the response to RAI 15.0-2 in which the staff asked the applicant to add a table in the DCD listing all of the nonsafety grade related systems and components used for mitigating transients and accidents analyzed in DCD Tier 2, Chapter 15. In response, the applicant stated that the response to RAI 15.0-2 addressed the nonsafety-related systems used for mitigating transients (anticipated operational occurrences and infrequent events) and accidents. Furthermore, the applicant stated that it had considered this discussion in its response to RAI 16.0-1. In these responses, the applicant stated that it had evaluated the following nonsafety-related systems:

- Control rod drive (CRD) system - makeup water function
- Fuel and auxiliary pool cooling system (FAPCS) - suppression pool cooling function
- Feedwater control system (FWCS)
- Rod control and information system (RC&IS)
- Steam bypass and pressure control (SB&PC) system

GEH determined that the functions of the above systems are not in the primary success path for mitigating transients and accidents and are not risk significant, except as noted below.

The applicant stated that it had determined that the following nonsafety-related-system functions are in the primary success path for mitigating transients:

- CRD system - selected control rod run-in (SCRRI) function (GTS 3.7.6)
- RC&IS - control rod block functions (GTS 3.3.2.1)
- SB&PC system - turbine bypass valve (TBV) opening function (GTS 3.7.4)

The staff finds the applicant's response acceptable except for the part concerning the FWCS. In RAI 16.2-33 S01, the staff asked GEH to clarify its response related to the role of the FWCS in mitigating the severity of transients (anticipated operational occurrences and infrequent events) by controlling RPV water level. RAI 16.2-33 was being tracked as an open item in the SER with open items. In response, GEH stated the following:

The FWCS is a normally-operating, non-safety-related system that is assumed to continue functioning after Anticipated Operational Occurrences (AOOs) and Infrequent Events (IEs), except where the failure of the FWCS is the initiator of an AOO or IE. Therefore, the FWCS is not required in the primary success path of the applicable AOOs and IEs. In addition, the FWCS is not credited for mitigating the consequences of any Design Basis Accident (DBA)....for AOOs and IEs, there is no requirement to assume the failure of the normally-operating, non-safety-related systems and components coincident with or after initiation of the AOO or IE event....failure of [the] FWCS simultaneously with an Inadvertent Isolation Condenser Initiation (IICI) event is a detectable and non-consequential random, independent failure, and the automatic function of the FWCS is thus not in the primary success path for the mitigation of the consequences of an IICI event....Since failure of FWCS to automatically control feedwater flow,

simultaneously with an IICI event is not deemed credible, only operation of the FWCS in manual control would prevent the automatic feedwater control that is assumed in response to an IICI event....[with FWCS in manual control] if an IICI event were to occur, it would be assumed that feedwater flow remains constant possibly impacting the MCPR resulting from the event....Since a basic assumption in the safety analysis for the IICI event is that the FWCS is in automatic control...in the calculation of the OLMCPR...operation of FWCS in manual mode would result in violating the requirements of Technical Specification 3.2.2, since the basic assumption of the OLMCPR as defined in the COLR would not be met...requiring restoration of automatic control of the FWCS [within 2 hours] or to reduce thermal power of the unit to less than 25% of rated thermal power [within 4 hours], as necessary.

The staff finds that the above information provides the requested clarification of the role of the FWCS in mitigating the severity of AOOs and IEs by controlling RPV water level, and concludes that the GTS do not need to include an LCO for the FWCS. However, the bases for GTS 3.2.2 did not specifically state that the MCPR operating limits specified in the COLR are not met whenever the unit is operating greater than or equal to 25 percent of the rated thermal power (RTP) in manual feedwater control. In RAI 16.2-33 S02, the staff requested that GEH revise the bases to address this point. In response, GEH added the following statement to the “ASA” section of the bases for GTS 3.2.2: “The transient analyses assume that the feedwater control system is in automatic mode; therefore, if the feedwater control system is in manual mode, then the MCPR LCO is not met.” If the MCPR LCO is not met, then the MCPR operating limits specified in the COLR are not met; the bases are clear that GTS 3.2.2, Action A, applies whenever the unit is operating at greater than or equal to 25 percent of the RTP in manual feedwater control. This is acceptable. Therefore, RAI 16.2-33 is resolved.

Based on consistency with the STS and the resolution of the above RAIs, the staff concludes that GTS Section 3.2 and bases are acceptable.

16.2.6 ESBWR GTS Section 3.3, “Instrumentation”

Section 3.3 of the GTS significantly differs from the instrumentation provisions in the STS. The use of microprocessor- or digital-based instrumentation systems in the ESBWR design is one source of the differences between the GTS and the STS. Another source of difference is the nonsafety-related designation of a number of the active systems in the ESBWR design that correspond to safety-related systems in the STS. The applicant determined that the four criteria of 10 CFR 50.36(c)(2)(ii) do not require instrumentation TS LCOs for such nonsafety-related systems. The resolution of RAI 16.0-1, regarding whether the process used by the applicant for the formulation of the ESBWR LCOs resulted in establishing LCOs meeting the requirements of 10 CFR 50.36(c)(2)(ii), supports this determination.

Section 3.3 of the ESBWR GTS contains the following instrumentation specifications and is generally based on the STS and the determinations made in response to RAI 16.0-1. Each of the following specifications contains LCO, action, and SRs for the associated instrumentation functions, consistent with 10 CFR 50.36, the design described in DCD Tier 2, Revision 9, Chapter 7 and the guidance provided in the STS:

- 3.3.1.1, “Reactor Protection System (RPS)”
- 3.3.1.2, “RPS Actuation”

- 3.3.1.3, “RPS Manual Actuation”
- 3.3.1.4, “Neutron Monitoring System (NMS) Instrumentation”
- 3.3.1.5, “NMS Automatic Actuation”
- 3.3.1.6, “SRNM Instrumentation”
- 3.3.2.1, “Control Rod Block (CRB) Instrumentation”
- 3.3.3.1, “Remote Shutdown System (RSS)”
- 3.3.3.2, “Post-Accident Monitoring (PAM) Instrumentation”
- 3.3.4.1, “Reactor Coolant System Leakage Detection (RCSLD) Instrumentation”
- 3.3.5.1, “Emergency Core Cooling System (ECCS) Instrumentation”
- 3.3.5.2, “ECCS Actuation”
- 3.3.5.3, “Isolation Condenser System (ICS) Instrumentation”
- 3.3.5.4, “ICS Actuation”
- 3.3.6.1, “Main Steam Isolation Valve (MSIV) Instrumentation”
- 3.3.6.2, “MSIV Actuation”
- 3.3.6.3, “Isolation Instrumentation”
- 3.3.6.4, “Isolation Actuation”
- 3.3.7.1, “Control Room Habitability Area (CRHA) Heating, Ventilation, and Air Conditioning (HVAC) Subsystem (CRHAVS)”
- 3.3.7.2, “CRHAVS Actuation”
- 3.3.8.1, “Diverse Protection System (DPS)”

Section 3.3 of the ESBWR GTS omits the following STS specifications. This is acceptable because each associated system either is not a part of the ESBWR design or is not safety related in the ESBWR design, as listed below.

Excluded STS instrumentation specifications associated with systems that are not a part of the ESBWR design are the following:

- 3.3.4.1, “End of Cycle Recirculation Pump Trip Instrumentation”
- 3.3.4.2, “Anticipated Transient Without Scram Recirculation Pump Trip Instrumentation”
- 3.3.5.2, “Reactor Core Isolation Cooling System Instrumentation”
- 3.3.6.4, “Suppression Pool Makeup System Instrumentation”

- 3.3.6.5, “Relief and Low-Low Set Instrumentation”
- 3.3.8.2, “RPS Electric Power Monitoring”

Excluded STS instrumentation specification associated with systems that are not safety related in the ESBWR design is the following:

- 3.3.6.3, “Residual Heat Removal Containment Spray System Instrumentation”

The following subsections describe the evaluation of the implementation of the requirements of 10 CFR 50.36(c) for LCOs, remedial actions (actions or required actions), and SRs in the specifications for ESBWR instrumentation.

16.2.6.1 Limiting Conditions for Operation

According to 10 CFR 50.36(c)(2)(i), LCOs are “the lowest functional capability or performance levels of equipment required for safe operation of the facility.” Accordingly, the proposed LCO for each instrumentation specification requires a corresponding minimum number of operable divisions or channels (as indicated below, depending on the specification) for each associated instrumentation function. For automatic functions, the minimum number is usually one more than the design requires to perform the safety function to account for a failure of the extra required division or channel. In the ESBWR design, the number of channels or divisions for a safety-related instrumentation function is typically one more than the LCO-specified minimum. See Chapter 7 of this report for an evaluation of the instrumentation design.

Generally, in the ESBWR GTS, an “instrumentation channel” refers to the process parameter sensor device and the circuit that carries the analog signal from the sensor to the analog-to-digital signal conversion device (e.g., a remote multiplexing unit [RMU] and a digital trip module [DTM]), where the digitized analog signal is compared to the trip setpoint. An “actuation division” refers to the digital trip signal from the DTM to logic processing, which develops an actuation signal to the final device (e.g., a valve initiator). In the case of the RPS, an actuation division includes a trip logic unit (TLU), an output logic unit (OLU), and load drivers. Thus, the GTS contain both an “instrumentation” specification and an “actuation” specification for the RPS, NMS, ECCS (automatic depressurization system [ADS] and gravity-driven cooling system [GDCS]), ICS, MSIV *isolation, containment* isolation, and CRHAVS.

The RPS trip logic and MSIV isolation functions of the reactor trip and isolation function (RTIF) platform use “de-energized-to-trip” and “failsafe” logic. For example, the RPS is able to scram the reactor if any two like and unbypassed parameters exceed their trip values.

The safety-related system logic and control/engineered safety feature (SSLC/ESF) trip logic uses “energized-to-trip” and “fail-as-is” logic. The isolated SSLC/ESF trip signal is transmitted via load drivers/discrete outputs to the actuators for protective action. The load drivers/discrete outputs are solid-state power switches, directing appropriate currents to devices such as the scram pilot valve solenoids, air-operated valves, and explosive-actuated squib valves.

Each required channel or division of a sensor or actuation function is supported by its own required division of the safety-related direct current (dc) and uninterruptible alternating current (ac) electrical power distribution system. An electrical power distribution division is required when it must be operable to meet LCO 3.8.6, “Distribution Systems - Operating,” or LCO 3.8.7, “Distribution Systems - Shutdown.”

For instrumentation functions that have four channels or divisions, the proposed LCOs require just three of the four channels or divisions to be operable. Any two channels or divisions are capable of performing the automatic safety function; requiring a third channel or division satisfies the single-failure criterion.

Some instrumentation functions have just two channels or divisions or the LCO requires just two channels or divisions to be operable. Except for the SRNM neutron flux monitoring function during spiral offloads or reloads in Mode 6, operability of these functions requires two channels or divisions to be operable. The following LCOs require two channels or divisions of instrumentation functions:

- 3.3.1.3, “RPS Manual Actuation” (two functions, two channels per function)
- 3.3.1.6, “SRNM Instrumentation” (one function, two channels; indication only)
- 3.3.2.1, “Control Rod Block (CRB) Instrumentation” (four functions, two channels per function)
- 3.3.3.1, “Remote Shutdown System (RSS)” (one function (manual scram), two divisions - Division 1 and Division 2 manual scram switches)
- 3.3.3.2, “Post-Accident Monitoring (PAM) Instrumentation” (multiple functions, two channels per function; indication only)

The instrumentation functions associated with these five LCOs, except for the SRNM, have just two channels or divisions, with each channel supported by its own safety-related electrical power distribution division - either Division 1 or Division 2. There are four SRNM channels (three detectors per channel), one channel for each division of electrical power. However, consistent with the STS; LCO 3.3.1.6 only requires two SRNM channels to be operable in Modes 3, 4, 5, and 6. In Mode 6 during certain refueling situations related to the location of fuel assemblies in the RPV, just one SRNM channel is required to be operable.

The remote shutdown system (RSS) consists of two redundant and independent panels located in the Division 1 and Division 2 quadrants of the reactor building. Division 1 and Division 2 and nonsafety-related parameters displayed and controlled on the MCR video display units (VDUs) can also be displayed and controlled from either of the two RSS panels. Each RSS panel has the ability to operate all of the nonsafety-related plant investment protection (PIP) equipment and the balance of plant equipment, either automatically or manually. However, the RSS instrumentation specification, GTS 3.3.3.1, only contains operability, action, and SRs for the Division 1 and Division 2 manual scram switches because manual scram is the only function that the operator needs to actuate to place and maintain the plant in hot shutdown (Mode 3) from a location other than the MCR. The safety-related ICS is designed to automatically maintain the unit in Mode 3 and Mode 4 by removing decay heat following reactor shutdown with the RPV isolated. For example, RPV isolation would automatically occur on a reactor vessel water level - low, Level 2 signal. In addition, the LCO only requires that the manual scram function be operable at one of the two RSS panels. Based on the above, LCO 3.3.3.1 is acceptable.

Unlike the bases for STS 3.3.3.2, the bases for ESBWR GTS 3.3.3.1 do not list the instrumentation functions needed to maintain the unit in hot shutdown. This is appropriate because each ESBWR RSS panel allows operator access to all functions and controls that are

available in the MCR, which include those for reactor scram, RCS decay heat removal (DHR), and RCS pressure control. Included controls are provided on PIP A and PIP B nonsafety-related VDUs, which enable operator control of the reactor water cleanup/shutdown cooling (RWCU/SDC) system, CRD system, reactor closed-cooling water (RCCW) system, plant service water (PSW) system, nonsafety-related electrical power distribution system, and the nuclear boiler system (NBS). These nonsafety-related systems are not required by GTS LCO 3.3.3.1, but they are described in the appropriate section of the DCD, which is listed in the "References" section of the bases for GTS 3.3.3.1. Safety-related controls on the RSS panels include the LCO-required Division 1 and 2 manual scram switches, the Division 1 and 2 MSIV (and drain isolation valve) isolation switches, and the Division 1 and 2 VDUs. DCD Section 7.4.2.2 describes the RSS and the instrumentation and controls provided on each RSS panel. Therefore, the bases for LCO 3.3.3.1 are acceptable.

The RCSLD instrumentation specification, GTS 3.3.4.1, requires three separate RCS leak detection systems, in conformance with RG 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection Systems," issued May 1973. These nonsafety monitoring functions of the leak detection and isolation system (LD&IS) are performed in the nonsafety-related distributed control and information system (N-DCIS) and provide indication and alarms to alert plant operators to increases in leakage, thereby supporting LCO 3.4.2, which specifies limits on RCS operational leakage. (See Section 16.2.6.3.4 of this report for the evaluation of GTS 3.3.4.1 action requirements and resolution of related RAIs.)

RAI 16.2-135 Equipment within an RPS division of trip actuators includes load drivers and controllers for automatic scram and air header dump (backup scram) initiation. LCO 3.3.1.2 addresses load drivers. The ESBWR GTS does not address operability requirements for the controllers. The staff asked the applicant to justify its decision to exclude controllers for automatic scram and air header dump (backup scram) initiation from the GTS. RAI 16.2-135 was being tracked as an open item in the SER with open items. In response, the applicant explained that the load drivers for the automatic scram function and the air header dump (backup scram) trip actuators (or "controllers" or "output contactors") both initiate a hydraulic scram by removing the instrument air pressure that keeps the scram valves shut. One air-operated scram valve is located on each hydraulic control unit scram accumulator; when the scram valve opens (i.e., when air pressure is exhausted), the associated control rods are hydraulically inserted into the core by the pressurized water in the scram accumulator. The applicant proposed to revise DCD Tier 2, Section 7.2.1.2.4.1 and the "Background" section of the bases for GTS 3.3.1.1 by clarifying the discussion of the divisions of trip actuators as follows:

Equipment within a division of trip actuators includes load drivers for automatic primary scram and output contactors for the initiation of backup scram....When in a tripped state, the load drivers within a division interconnect with the Output Logic Unit (OLU) of all other divisions to form an arrangement (connected in series and in parallel in two separate groups) that results in two-out-of-four scram logic. Reactor scram occurs if load drivers associated with any two or more divisions receive trip signals from the OLUs....When in a tripped state, the output contactors cause the backup scram valve solenoids to energize. The output contactors of the backup scram are arranged in a two-out-of-four configuration similar to that...for the primary scram load drivers. Backup scram is diverse in power source and function to primary scram....OPERABILITY requirements for the [automatic primary scram] load drivers are addressed in LCO 3.3.1.2.

OPERABILITY requirements for the backup scram [output contactors] are not addressed within the Technical Specifications.

In response to a manual or automatic scram signal (two-out-of-four logic) from the RPS, safety-related power is removed from each primary scram pilot valve solenoid, which positions each primary scram valve to exhaust air from the associated hydraulic control unit (HCU) scram valve air operator, allowing the HCU scram valve to open causing a hydraulic scram of the associated control rods by the pressurized water in the scram accumulators.

In response to a manual or automatic scram signal from the RPS (two-out-of-four logic), safety-related power is supplied to each backup scram valve solenoid, which positions each backup scram valve to isolate instrument air from the scram air header and exhaust air from the scram air header and the air operator of each HCU scram valve, allowing all HCU scram valves to open causing a hydraulic scram of all control rods by the pressurized water in the scram accumulators.

Further, as described in DCD Tier 2, Revision 9, Section 7.2.1, the backup scram valves are not safety related and the backup scram has a separate and independent power source and function from the primary scram. The staff concluded that the backup scram valves, including the solenoids and output contactors, do not satisfy any of the LCO criteria of 10 CFR 50.36 because they are not the primary means of initiating a hydraulic scram of the control rods in response to a scram signal from the RPS, and therefore need not be specified in a GTS LCO. Based on this conclusion, the design of the backup scram function, and the applicant's response, RAI 16.2-135 is resolved.

RAI 16.2-136 The LCO for RPS manual actuation states that the Division 1 and 2 manual actuation channels and mode switch actuation channels must be operable. The staff asked the applicant to revise the LCO of GTS Section 3.3.1.3, "Reactor Protection System Manual Actuation," to add the number of channels required to be operable for each manual actuation feature. RAI 16.2-136 was being tracked as an open item in the SER with open items. In response, GEH revised GTS 3.3.1.3 and associated bases to specify the number of channels required to be operable for each manual function by referencing new Table 3.3.1.3-1 in GTS LCO 3.3.1.3, which specifies the manual functions, their applicable modes, and the number of channels required operable. Specifically, two channels each of the manual scram function and reactor mode switch-shutdown position function are required to be operable in Modes 1 and 2 and in Mode 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies. Because GEH made the requested changes to GTS 3.3.1.3 and bases to explicitly state the required number of operable channels for each RPS manual function, therefore, RAI 16.2-136 is resolved.

RAI 16.2-139 Instrumentation LCOs state the number of divisions required to be operable, whereas associated actions conditions refer to inoperable required channels. The staff asked the applicant to revise LCOs to state the number of channels required to be operable for each division. RAI 16.2-139 was being tracked as an open item in the SER with open items. In response, the applicant stated that it had revised GTS LCO 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," and Table 3.3.1.4-1 to explicitly state the required number of operable channels per required division for each function identified in DCD Revision 4, Chapter 16, Table 3.3.1.4-1. LCO 3.3.1.4 states the following:

The NMS instrumentation channels of the three NMS instrumentation divisions associated with the DC and Uninterruptible AC Electrical Power Distribution

Divisions required by LCO 3.8.6, "Distribution Systems - Operating," and LCO 3.8.7, "Distribution Systems - Shutdown," for each Function in Table 3.3.1.4-1 shall be OPERABLE.

In addition, DCD Revision 5, Chapter 16 revised Action A of GTS 3.3.1.4 by adding "instrumentation" to Condition A for consistency with the LCO phrasing and to Required Action A.1 for clarity and consistency with the design, as follows:

- Condition A One or more Functions with instrumentation channel(s) inoperable in one required division.
- Required Action A.1 Verify associated instrument channel in trip.
- Completion Time 12 hours

These changes provided the requested clarification for LCO 3.3.1.4. The staff verified that DCD Revision 5, Chapter 16 had also clarified the channels-per-division issue for the other LCOs in GTS Section 3.3. Therefore, RAI 16.2-139 is resolved.

RAI 16.2-186 The staff asked the applicant to correct an inconsistency between DCD Tier 2, Revision 5, Section 4.6.1.2.6 and RPS Function 3 of GTS 3.3.1.1 and 3.3.2.1. Function 3 does not use "low low" and "hydraulic control unit" in its name, and GTS 3.3.2.1 does not specify the control rod block (CRB) function, "low pressure in the HCU accumulator charging water header." In response, GEH corrected the inconsistencies by revising DCD Tier 1, Chapter 2, and DCD Tier 2, Chapters 1, 4, 7, 15, 16, and 16B. Regarding RPS Function 3, the applicant replaced the terms "CRD accumulator" or "HCU accumulator" with the term "scram accumulator." GEH corrected the CRB function inconsistency by replacing various references to "[CRD][HCU] charging [water] header" with the reference "scram accumulator charging water header." In addition, GEH changed RPS Function 3 to "scram accumulator charging water header pressure - low-low," and the CRB function to "scram accumulator charging water header pressure - low." These nomenclature changes clarify the DCD description of these functions and the presentation of requirements in the GTS. Therefore, they are acceptable. GEH also stated that it had determined that the CRB function, "scram accumulator charging water header pressure - low," did not satisfy any of the criteria of 10 CFR 50.36(c)(2)(ii) because it is not credited in the "safety analyses and is not significant to public health and safety." Based on this determination and the correction of the noted inconsistencies, therefore, RAI 16.2-186 is resolved.

RAI 16.2-187 The staff asked the applicant to justify its decision not to specify several instrumentation functions, which are described in DCD Tier 2, Section 4.6.1.2.5, "Control Rod Drive System Operation." In response, GEH stated that all but one of the functions did not meet the criteria of 10 CFR 50.36(c)(2)(ii). The staff reviewed the justification provided in the response and found it to be acceptable. GEH referred to the response to RAI 21.6-103 in which it had concluded that the GTS should specify instrumentation and actuation functions for automatic stop of CRD pumps on coincident low level in two GDSCS pools. In DCD Revision 6, GEH added "GDSCS Pool Water Level Low" (Function 14 of GTS 3.3.6.3) and "High Pressure Control Rod Drive Isolation" (Function 11 of GTS 3.3.6.4). Therefore, RAI 16.2-187 is resolved.

RAI 16.2-190 The STS for BWRs include a specification, STS 3.3.3.1, to govern PAM instrumentation which is based on RG 1.97, "Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants," Revision 3, and the T.E. Murley (NRC) to R. F. Janecek (BWR Owners' Group) letter regarding the NRC staff review of nuclear steam supply system vendor owners groups' application of the Commission's interim policy statement criteria to standard technical

specifications, which presents the current staff position regarding which accident monitoring instrumentation must be in TS. This letter is known as the “Split Report.” The bases for STS 3.3.3.1, state:

PAM instrumentation that meets the definition of Type A in RG 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Category 1, non-Type A, instrumentation is retained in the Technical Specifications because it is intended to assist operators in minimizing the consequences of accidents. Therefore, these Category 1, non-Type A variables are important for reducing public risk.

In addition, STS 3.3.3.1 contains a Reviewer’s Note for applicants or Licensees who propose to incorporate STS 3.3.3.1 into their plant’s TS. The Note requires replacing the bracketed list of PAM functions in STS Table 3.3.3.1-1 with a list of all RG 1.97 Type A instruments, and the Category 1, non-Type A instruments specified in the plant’s RG 1.97 Safety Evaluation Report. STS 3.3.3.1 and bases, and the STS Table 3.3.3.1-1 Reviewer’s Note are consistent with the current staff position on accident monitoring instrumentation TS, which is articulated in the “Split Report.”

The staff reviewed its current position regarding which accident monitoring instrumentation should be in the TS as compared to RG 1.97, Revision 4, “Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants.” Based on that review, the staff concludes the following:

1. Accident monitoring instrumentation Type A, as defined in RG 1.97, Revision 4, is similar to the Type A as defined in RG 1.97, Revision 3.
2. Accident monitoring instrumentation Type B and Type C, as defined RG 1.97, Revision 4, are similar to the Category 1 type of accident monitoring instrumentation as defined in RG 1.97, Revision 3.

Therefore, the staff concludes that TS should include (1) all RG 1.97, Revision 4, Type A instruments, and (2) all RG 1.97, Revision 4, Type B and Type C instruments. The staff notes that GEH has committed to following the guidance in RG 1.97, Revision 4, in its design certification application for the ESBWR.

Since STS for BWRs include TS to govern PAM instrumentation, in RAI 16.2-190 the staff asked GEH to include requirements for PAM instrumentation in the ESBWR GTS. This would include removing the brackets from the entire GTS 3.3.3.2, as presented in DCD Revision 6, and possibly a bracketed list of the potential Type A, Type B, and Type C PAM instrumentation functions in GTS Table 3.3.3.2-1.

Regardless of whether an ESBWR COL application references Revision 4 or Revision 3 of RG 1.97, the applicant would have to finalize the PAM instrumentation function list to complete GTS Table 3.3.3.2-1. However, if the COL applicant references Revision 4, finalizing the PAM instrumentation function list may not be possible before COL issuance. In RAI 16.2-190, the staff pointed out to the applicant that identification of Type A, Type B, and Type C accident monitoring instrumentation functions as defined in RG 1.97, Revision 4, depends on development of emergency operating procedures and abnormal operating procedures, which is a post-COL activity. Therefore COL applicants implementing RG 1.97, Revision 4, should use guidance from DC/COL-ISG-8 to finalize the list of PAM instrumentation functions in GTS Table 3.3.3.2-1.

In RAI 16.2-190, the staff suggested that GEH modify the GTS and bases, and DCD Tier 2, Table 16.0-1-A to include a choice for the COL applicant to use Option 2 of DC/COL-ISG-8 to provide a site-specific bounding list of accident monitoring functions in GTS Table 3.3.3.2-1; or Option 3 of DC/COL-ISG-8 to remove GTS Table 3.3.3.2-1 and add a GTS programmatic requirement for identifying PAM functions in accordance with the NRC approved methodology endorsed by RG 1.97, Revision 4. Alternatively, the staff suggested that GEH consider modifying the GTS and bases, and DCD Tier 2, Table 16.0-1-A to specify the programmatic option, so that ESBWR COL applications could incorporate it by reference. Finally, the staff requested that GEH also revise the actions of GTS 3.3.3.2 to be consistent with STS 3.3.3.1, as discussed in Section 16.2.6.3.3 of this report.

In response, GEH stated it would revise the GTS and bases, and DCD Tier 2, Table 16.0-1-A to specify the programmatic option. The staff reviewed the markup of the affected pages in DCD Tier 2, Section 16.0 and in the GTS and bases and found that they proposed all of the changes needed to incorporate the programmatic option suggested in the RAI. Therefore, GTS 3.3.3.2 and bases, GTS 5.5.14, and GTS 5.6.5 are acceptable. In addition, COL Items 3.3.3.2-1 and 5.6.5-1 in DCD Tier 2, Revision 6, Table 16.0-1-A were deleted. Based on these changes, RAI 16.2-190 is resolved. The staff verified that DCD Revision 8 includes the described changes. As discussed in Section 22.5.9 of this report, based on the changes associated with this RAI response, GEH also deleted Availability Control (AC) 3.3.4 from DCD Tier 2, Chapter 19ACM.

The staff compared the proposed instrumentation LCOs and associated bases to the instrumentation system design descriptions in DCD Tier 2, Chapter 7, and the applicant's response to RAI 16.0-1 regarding compliance with 10 CFR 50.36(c)(2)(ii) criteria. The staff concludes that GEH has identified the instrumentation functions that are required to be the subject of LCOs in the GTS. The staff notes that several instrumentation functions are specified in GTS sections other than Section 3.3. This is an acceptable difference in presentation from that of the STS. Based on the preceding evaluations and the resolution of LCO-related RAIs, the staff concludes that the proposed instrumentation LCOs and associated bases sections regarding "Background," "ASA" and "LCO" are acceptable.

16.2.6.2 Applicability

The staff verified that the reactor operating modes or other specified conditions stated in the applicability for each proposed instrumentation function are appropriate to ensure that the function's LCO will be met under plant conditions and evolutions for which the function is required by the ESBWR accident analyses or other governing regulatory requirements (such as for RSS and PAM instrumentation). Based on this and the resolution of the following RAI, the proposed applicability requirements for GTS Section 3.3 specifications are acceptable.

RAI 16.2-141. The staff asked the applicant to explain an apparent overlap of requirements for the SRNM instrumentation in Mode 6. GTS 3.3.1.6, "Startup Range Neutron Monitor Instrumentation," and 3.3.1.4, "Neutron Monitoring System (NMS) Instrumentation," require the SRNMs to be operable in Mode 6. The staff also asked the applicant to explain why SRNM channel calibration is required to be performed, in accordance with GTS 5.5.11, "Setpoint Control Program (SCP)," in GTS 3.3.1.4 but not in GTS 3.3.1.6. RAI 16.2-141 was being tracked as an open item in the SER with open items.

In response, the applicant stated that the functional requirements for the SRNM instrumentation are not duplicated in LCO 3.3.1.4 and LCO 3.3.1.6. The SRNM subsystem

Functions 3.3.1.4.1.a, “SRNM Neutron Flux - High,” and 3.3.1.4.1.c, “SRNM Inop,” are required to be operable in Mode 6 with any control rod withdrawn from a core cell containing one or more fuel assemblies. These functions generate a scram trip signal to prevent fuel damage in the event of any abnormal positive reactivity insertion transients while operating in the startup power range. In contrast, LCO 3.3.1.6 specifies operability requirements only for the monitoring and indication functions of the SRNM instrumentation, which monitors reactivity changes during fuel or control rod movement to provide plant operators an early indication of unexpected subcritical multiplication that could be indicative of an approach to criticality. Since the SRNM monitoring and indication functions have no trip settings for generating a trip signal, the staff finds that the setpoint control program (SCP) does not apply to SR 3.3.1.6.5, which requires a channel calibration to verify the performance of the SRNM detectors and associated circuitry. Therefore, RAI 16.2-141 is resolved.

16.2.6.3 Instrumentation Action Requirements

According to 10 CFR 50.36(c)(2)(i), “when a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.” Thus, for each function, each instrumentation specification includes remedial actions, consistent with the STS format, in the form of required actions that must be performed within specified completion times for various conditions of not meeting the LCO.

16.2.6.3.1 Separate Condition Entry

GTS Section 1.3 specifies that once an actions condition is entered, subsequent divisions, subsystems, components, or variables expressed in the condition that are discovered to be concurrently inoperable or not within limits will not result in separate entry into the condition. Section 1.3 also specifies that required actions of the condition continue to apply for each additional failure, with completion times based on initial entry into the condition. However, separate condition entry (meaning a separate completion time for each subsequent condition entry) is acceptable when the actions provide appropriate compensatory measures for separate inoperable channels, divisions, or functions. The appropriate compensatory measure in such a loss of function condition is to immediately take the specified required actions that usually include shutting down the unit or declaring associated supported equipment or trains inoperable.

The actions for RPS, NMS, MSIV, Isolation, ECCS, ICS, CRHAVS, and DPS instrumentation specifications contain a note that allows separate condition entry for each channel, division, or function, as appropriate. Separate condition entry is appropriate because the required actions, as discussed below, provide appropriate compensatory measures for concurrently inoperable channels, divisions, or functions. Separate condition entry is permitted for each channel, division, or function, as described in Table 16-1.

The applicant did not propose an actions note allowing separate condition entry for the following instrumentation specifications:

- 3.3.1.6, “SRNM Instrumentation”
- 3.3.2.1, “Control Rod Block Instrumentation”
- 3.3.4.1, “Reactor Coolant System (RCS) Leakage Detection Instrumentation”
- 3.3.7.2, “CRHAVS Actuation”

Table 16-1. Summary of Basis for Separate Condition Entry into Instrumentation LCO Actions Conditions

Basis—Channel, Division, or Function:	LCO Requirement:
<ul style="list-style-type: none"> RPS instrumentation channel 	LCO 3.3.1.1 specifies 16 functions and requires three instrumentation channels to be operable for each function (one channel for each of three required electrical divisions).
<ul style="list-style-type: none"> RPS automatic actuation division 	LCO 3.3.1.2 specifies one function and requires three automatic trip actuation divisions to be operable (one division for each of three required electrical divisions).
<ul style="list-style-type: none"> RPS manual actuation function 	LCO 3.3.1.3 specifies two functions and requires two channels to be operable for each function (one channel for each of two required electrical divisions).
<ul style="list-style-type: none"> NMS instrument channel 	LCO 3.3.1.4 specifies seven functions and requires three or six channels to be operable for each function (one or two [Functions 1.a and 1.b] channels for each of three required electrical divisions).
<ul style="list-style-type: none"> NMS automatic actuation division 	LCO 3.3.1.5 specifies three functions and requires three automatic actuation divisions to be operable for each function (one division for each of three required electrical divisions).
<ul style="list-style-type: none"> RSS function 	LCO 3.3.3.1 specifies one function and requires two channels to be operable for that function (one channel for each of two required electrical divisions, Divisions 1 and 2). (RPS Divisions 1 and 2 manual scram switches located on one of the two RSS panels.)
<ul style="list-style-type: none"> PAM function 	LCO 3.3.3.2 specifies multiple functions (to be determined in accordance with Specification 5.5.14) and requires two channels to be operable for each function (one channel for each of two required electrical divisions, Divisions 1 and 2).
<ul style="list-style-type: none"> ECCS instrumentation channel 	LCO 3.3.5.1 specifies three functions and requires three channels to be operable for each function (one channel for each of three required electrical divisions).

Basis—Channel, Division, or Function:	LCO Requirement:
• ECCS actuation function	LCO 3.3.5.2 specifies four functions and requires three actuation divisions to be operable for each function (one actuation division for each of three required electrical divisions).
• ICS instrumentation channel	LCO 3.3.5.3 specifies six functions and requires three channels to be operable for each function (one channel for each of three required electrical divisions).
• ICS actuation division	LCO 3.3.5.4 specifies two function and requires three actuation divisions to be operable for each function (one actuation division for each of three required electrical divisions).
• MSIV instrumentation channel	LCO 3.3.6.1 specifies seven functions and requires three channels to be operable for each function (one channel for each of three required electrical divisions).
• MSIV actuation division	LCO 3.3.6.2 specifies one function and requires three actuation divisions to be operable for that function (one actuation division for each of three required electrical divisions).
• Isolation instrumentation channel	LCO 3.3.6.3 specifies 14 functions and requires three channels to be operable for each function (one channel for each of three required electrical divisions).
• Isolation actuation division	LCO 3.3.6.4 specifies 11 functions and requires three actuation divisions to be operable for each function (one actuation division for each of three required electrical divisions).
• CRHAVS instrumentation channel	LCO 3.3.7.1 specifies four functions and requires three channels to be operable for each function (one channel for each of three required electrical divisions).
• DPS function	LCO 3.3.8.1 specifies three automatic instrument functions, two manual instrument functions, and five actuation functions. Three nonsafety, nondivisional load groups provide uninterruptible 120-volt ac electrical power to the required DPS functions.

RAIs 16.2-137 and 16.2-138 The staff asked the applicant in RAI 16.2-137 to revise the actions note of GTS 3.3.1.3, “Reactor Protection System Manual Actuation,” which permits separate condition entry for each function, to match the per-channel requirements in the LCO. In

RAI 16.2-138, the staff requested that the applicant revise the actions of GTS 3.3.1.3 to require placing the unit in Mode 3 in 12 hours if both channels for one or both manual actuation functions are inoperable with the unit in Mode 1 or 2, or during refueling to initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.

RAIs 16.2-137 and 16.2-138 were being tracked as open items in the SER with open items. In response, GEH revised the actions as requested, as well as the actions note, to allow separate condition entry for each manual function. The staff finds that these changes are acceptable because they are consistent with the response to RAI 16.2-136 (described previously) regarding the number of channels required to be operable for each RPS manual actuation function by LCO 3.3.1.3. Therefore, RAIs 16.2-137 and 16.2-138 are resolved.

16.2.6.3.2 Actions for Functions with Three Required Instrumentation Channels and Functions with Three Required Actuation Divisions

For functions designed with four instrumentation channels, or functions designed with four actuation divisions, three are sufficient to withstand a single failure. Therefore, the initial action requirement in each of the specifications for these functions addresses the condition of a loss of capability to withstand a single failure and still maintain functional capability. Subsequent action requirements address either failure to recover the capability to withstand a single failure or loss of functional capability altogether.

For the condition of one inoperable required instrumentation channel for one or more functions, the GTS actions require, depending on the specification, either restoring the required instrument channel (for all affected functions) to operable status within 12 hours or verifying that the inoperable required instrument channel (for all affected functions) is in trip within 12 hours.

For the condition of one inoperable required actuation division for one or more functions, the GTS actions require, depending on the specification, either restoring the required actuation division (for all affected functions, except for ECCS actuation functions) to operable status within 12 hours (except for an inoperable required isolation actuation division, which specifies 4 hours), or verifying that the inoperable required actuation division (for all affected functions) is in trip within 12 hours. GTS 3.3.5.2 allows separate condition entry for each of four ECCS actuation functions, instead of for each of the three required actuation divisions. Thus, Action A allows 12 hours to restore an inoperable division to operable status for each ECCS actuation function.

During the 12-hour or 4-hour completion time, the inoperable required instrumentation channel or actuation division may be placed in bypass, provided that the non-required instrumentation channel or actuation division is operable and not placed in bypass. Only one instrumentation channel or actuation division may be placed in bypass at a time. Also during the 12-hour or 4-hour completion time, the occurrence of a single failure could cause a complete loss of capability of the affected automatic safety function (loss of trip or actuation capability for that function).

16.2.6.3.2.1 *Loss of Capability to Withstand a Single Failure—Action A*

16.2.6.3.2.1.1 RPS, NMS, and MSIV Functions for Required Instrumentation Channels and Actuation Divisions

The condition of one inoperable required instrument channel or actuation division for one or more functions corresponds to an inability to sustain an additional failure in either of the

remaining two required instrument channels (for the affected functions) or actuation divisions (for the affected actuation functions). Table 16-2 lists the GTS Revision 9 action requirements for this condition for the RPS, NMS, and MSIV functions; the staff added the italicized words to clarify the context of each condition and action. The completion time for each required action is 12 hours.

By STS convention, restoring the inoperable instrument channel or actuation division to operable status within the specified completion time is also understood as an optional specified required action.

For the condition of one inoperable required instrument channel for more than one function, once the channel for one of the functions is restored to operable status, the completion time is not reset, but continues from the time the channel for the first function was declared inoperable (from the time the condition was initially entered). The completion time may be extended if the function of the channel restored to operable status was the first function with the inoperable channel. The completion time may be extended for up to 12 hours provided this does not result in the same channel for any subsequent function being inoperable or not in trip for more than 12 hours. This extension is consistent with GTS Example 1.3-4 and is therefore, acceptable.

Table 16-2. Summary of Actions for Loss of Capability to Withstand a Single Failure for RPS, NMS, and MSIV Instrumentation and Actuation Functions.

LCO:	Condition A:	Required Action A.1:
3.1.1.1	One or more <i>RPS</i> functions with one required instrumentation channel inoperable.	Verify associated <i>RPS</i> instrument channel in trip.
3.3.1.2	One required RPS automatic actuation division inoperable.	Verify required <i>RPS automatic actuation</i> division in trip.
3.3.1.4	One or more <i>NMS</i> functions with instrumentation channel(s) inoperable in one required division.	Verify associated <i>NMS</i> instrument channel in trip.
3.3.1.5	One or more <i>NMS automatic actuation</i> functions with one required division inoperable.	Verify required <i>NMS automatic actuation</i> division in trip.
3.3.6.1	One or more <i>MSIV instrumentation</i> functions with one required channel inoperable.	Verify associated <i>MSIV</i> instrument channel in trip.
3.3.6.2	One required MSIV actuation division inoperable.	Verify required MSIV actuation division in trip.

For the condition of one inoperable required actuation division for more than one actuation function, once the actuation division for one of the actuation functions is restored to operable status, the completion time is not reset, but continues from the time the actuation division for the first actuation function was declared inoperable (from the time the condition was initially entered). The completion time may be extended if the actuation function of the actuation division that was restored to operable status was the first actuation function with the inoperable actuation division. The completion time may be extended for up to 12 hours provided this does not result in the same actuation division for any subsequent actuation function being inoperable

or not in trip for more than 12 hours. This extension is consistent with GTS Example 1.3-4 and is therefore acceptable.

With one instrument channel or actuation division in trip, just one of the two remaining instrument channels or actuation divisions is needed to initiate an automatic safety actuation, such as reactor trip or main steam line isolation (MSLI). Also, an additional single failure affecting one of the two remaining instrument channels or actuation divisions would not defeat the automatic safety actuation. Therefore, continued operation is permitted without a time limit in this condition. However, the chance of a spurious trip or actuation is increased.

16.2.6.3.2.1.2 ECCS, ICS, Isolation, and CRHAVS Functions for Required Instrumentation Channels and Actuation Divisions

The condition of one inoperable required instrument channel or actuation division for one or more functions corresponds to an inability to sustain an additional failure in either of the remaining two required instrument channels or actuation divisions. Table 16-3 lists the GTS Revision 9 action requirements for this condition for the ECCS, ICS, isolation, and CRHAVS functions; the staff added the italicized words to clarify the context of each condition and action. In the following actions conditions, for the condition of one or more functions with one of the three required instrumentation channels or actuation divisions inoperable, the actions require that, within 12 hours, all inoperable functions in that channel or division be restored to operable status, with two exceptions. For the condition of one inoperable required isolation actuation division for one or more functions, the GTS 3.3.6.4 actions require restoring the required isolation actuation division (for all functions) to operable status within 4 hours. The 4-hour completion time is consistent with the action requirements of GTS 3.6.1.3, "Containment Isolation Valves." The second exception stems from the allowance for separate condition entry for each ECCS actuation function in GTS 3.3.5.2.

For the condition of one inoperable required instrument channel for more than one function, once the channel for one of the functions is restored to operable status, the completion time is not reset, but continues from the time the channel for the first function was declared inoperable (from the time the condition was initially entered for that channel). The completion time may be extended if the function of the channel that was restored to operable status was the first function with the inoperable channel. The completion time may be extended for up to 12 hours provided this does not result in the same channel for any subsequent function being inoperable for more than 12 hours. This extension is consistent with GTS Example 1.3-4 and is therefore acceptable.

Table 16-3. Summary of Actions for Loss of Capability to Withstand a Single Failure for ECCS, ICS, Isolation, and CRHAVS Instrumentation and Actuation Functions.

LCO:	Condition A:	Required Action A.1:
3.3.5.1	One or more <i>ECCS</i> functions with one required <i>ECCS</i> instrumentation channel inoperable.	Restore required <i>ECCS instrument</i> channel to OPERABLE status.
3.3.5.2	One or more <i>ECCS actuation</i> functions with one required <i>ECCS</i> actuation division inoperable.	Restore required <i>ECCS actuation</i> division to OPERABLE status.
3.3.5.3	One or more <i>ICS</i> functions with one required <i>ICS</i> instrumentation channel inoperable.	Restore required <i>ICS instrumentation</i> channel to OPERABLE status.
3.3.5.4	One or more <i>ICS actuation</i> Functions with one required <i>ICS</i> actuation <i>logic</i> division inoperable.	Restore required <i>ICS actuation logic</i> division to OPERABLE status.
3.3.6.3	One or more <i>isolation</i> functions with one required <i>isolation</i> instrumentation channel inoperable.	Restore required <i>isolation instrument</i> channel to OPERABLE status.
3.3.6.4	One or more <i>isolation actuation</i> functions with one or more required isolation actuation divisions inoperable.	Restore required <i>isolation actuation</i> division(s) to OPERABLE status.
3.3.7.1	One or more <i>CRHAVS</i> functions with one required instrumentation channel inoperable.	Restore required <i>CRHAVS instrument</i> channel to OPERABLE status.
3.3.7.2	One required <i>CRHAVS</i> actuation division inoperable.	Restore required <i>CRHAVS actuation</i> division to OPERABLE status.

For the condition of one inoperable required actuation division for more than one function (except for an inoperable ECCS actuation division), once the actuation division for one of the functions is restored to operable status, the completion time is not reset, but continues from the time the actuation division for the first function was declared inoperable (from the time the condition was initially entered for that actuation division). The completion time may be extended if the function of the actuation division that was restored to operable status was the first function with the inoperable actuation division. The completion time may be extended for up to 12 hours (4 hours for isolation actuation division) provided that this does not result in the same actuation division for any subsequent function being inoperable for more than 12 hours (4 hours). This extension is consistent with GTS Example 1.3-4 and is therefore acceptable.

GTS 3.3.5.2, Condition A for one inoperable required ECCS actuation division for more than one ECCS actuation function is equivalent to the condition of one inoperable required ECCS actuation division, regardless of how many functions are affected. This is because separate condition entry is allowed for each ECCS actuation function. If a second actuation division for

the same function is determined to be inoperable, Action B requires the affected ECCS components to immediately be declared inoperable, which would require a unit shutdown. However, if the first inoperable actuation division is subsequently restored to operable status, Action B is exited, and the completion time for Action A continues from the time the restored actuation division for the affected function was declared inoperable (i.e., from the time of initial entry into Condition A). The completion time may be extended if the actuation division that was restored to operable status was the first inoperable actuation division. The completion time may be extended for up to 12 hours provided that this does not result in any subsequent actuation division for that function being inoperable for more than 12 hours. This extension is consistent with GTS Example 1.3-4 and is therefore acceptable.

During the 12-hour or 4-hour completion time, the inoperable required instrumentation channel, actuation division, or isolation actuation division may be placed in bypass, provided that the non-required instrumentation channel, actuation division, or isolation actuation division is operable and not placed in bypass. Only one instrumentation channel or actuation division may be placed in bypass at a time. The bypass feature affects all instrument functions for a given channel or all actuation functions for a given actuation division. In addition, during the 12-hour or 4-hour completion time, the occurrence of a single failure could cause a complete loss of capability of the affected automatic safety function (loss of trip or actuation capability for that function).

Placing the inoperable instrumentation channel or actuation division in trip is not specified for the ECCS, ICS, Isolation, and CRHAVS functions in order to minimize the chance of a spurious actuation of the ECCS, ICS, Isolation System and CRHAVS.

The 12-hour and 4-hour completion times are based on engineering judgment, considering the low probability of an event requiring actuation of the function during this interval and the capability of the automatic functions in the remaining required instrument channels or actuation divisions to initiate all safety functions assumed in the accident analysis. Therefore, Required Action A.1 for each of the listed conditions is acceptable.

16.2.6.3.2.2 *Functional Capability Not Maintained or Required Action and Associated Completion Time of Condition A Not Met—Action B*

16.2.6.3.2.2.1 RPS, NMS, MSIV, Isolation, and CRHAVS Functions for Required Instrumentation Channels; and NMS and Isolation Actuation Functions for Required Actuation Divisions

In the specified conditions listed in Table 16-4 of this report (either “Required Action and Associated Completion Time of Condition A not met,” or “one or more functions with trip (or actuation, or isolation, or isolation actuation) capability not maintained”), Required Action B.1 requires immediately entering the Condition as listed in the associated table for the RPS, NMS, MSIV, Isolation, and CRHAVS instrumentation functions, and also for the NMS and Isolation actuation functions. The staff added the italicized words to clarify the context of each condition and action.

Required Action B.1 of GTS 3.3.1.4 and GTS 3.3.1.5, as noted in Table 16-4, requires entering the Condition referenced in Tables 3.3.1.4-1 and 3.3.1.5-1, respectively. For NMS instrument Function 3, “Oscillation Power Range Monitor - Upscale,” and NMS actuation Function 3, “Oscillation Power Range Monitors,” Actions E and C, respectively, both require within 12 hours initiating an alternate method to detect and suppress thermal-hydraulic instability oscillations

and within 120 days restoring required channels to operable status. The bases for GTS 3.3.1.4 and GTS 3.3.1.5 state the following:

The 120-day Completion Time is considered adequate based on engineering judgment considering that with operation minimized in regions where oscillations may occur and implementation of the alternate methods, the likelihood of an instability event that could not be adequately handled by the alternate methods during this 120-day period was negligibly small.

This is consistent with Required Action J.1 of GTS 3.3.1.1 for the advanced boiling water reactor (ABWR) certified design, which requires, for the condition of failure to restore inoperable oscillation power range monitors (OPRM) channels to operable status within the specified completion time, immediately initiating action to place the reactor power/flow relationship outside of the region of applicability shown in Figure 3.3.1.1-1, "Oscillation Power Range Function Conditions of Operability." The ABWR GTS bases state that, "The potential for power oscillations in a BWR is restricted to operation conditions with low core flow and relatively high power."

Ensuring that core flow is greater than 60 percent of full flow or that power is less than 30 percent RTP precludes power oscillations. Outside these limits, the OPRM is not required to be operable; therefore, continued operation outside the applicable region may continue indefinitely. However, in the ESBWR, core flow is achieved by natural circulation and cannot be increased by use of pumps, such as those provided in the ABWR and BWR/6 designs. Therefore, operation may not continue indefinitely with an inoperable OPRM-Upscale instrumentation or actuation function, but is limited to 120 days, provided that alternate methods have been implemented for detecting and suppressing thermal-hydraulic instability oscillations. In addition, the ESBWR accident analyses do not assume the OPRM-Upscale function, and the ESBWR is designed to preclude operation in the power-flow region in which power oscillations can occur. For these reasons, the staff finds the 120-day operational restriction acceptable.

Required Action B.1 of GTS 3.3.7.1 requires entering Action C for CRHAVS instrumentation Function 1, "Control Room Air Intake Radiation - High," and Function 2, "Extended Loss of AC Power." Action C requires immediately isolating the CRHA boundary and placing the operable CRHAVS train in isolation mode, which accomplishes the objectives of the two inoperable functions; Action C alternatively requires declaring both CRHAVS trains inoperable. This is appropriate; GTS 3.7.2, Action D, would apply in Modes 1, 2, 3, and 4, and would require placing the unit in Mode 3 in 12 hours and Mode 5 in 36 hours. During operations with a potential for draining the reactor vessel (OPDRVs), Action E would apply and would require immediately initiating action to suspend OPDRVs. These actions are acceptable because they place the unit outside the GTS Applicability of the CRHAVS and supporting instrumentation.

Required Action B.1 of GTS 3.3.7.1 requires entering Action D for CRHAVS instrumentation Function 3, "EFU Discharge Flow - Low (primary train), and Function 4, "EFU Outlet Radiation - High-High (primary train)." Required Action D.1 requires immediately declaring the standby CRHAVS train inoperable, which is appropriate because loss of Function 3 or 4 degrades or removes the standby automatic actuation capability of the standby train upon failure of the primary train filters or fans. This is also appropriate because GTS 3.7.2 Action C would apply and would require restoring the inoperable train to operable status in 7 days, which is consistent with STS 3.7.3 and therefore acceptable.

Table 16-4. Summary of Actions for the Condition of Required Action and Associated Completion Time of Condition A Not Met or Functional Capability Not Maintained for RPS, NMS, MSIV, Isolation, and CRHAVS Instrumentation Functions, and NMS and Isolation Actuation Functions.

LCO:	Condition B—Required Action and associated Completion Time of Condition A not met. <u>OR:</u>	Required Action B.1—Immediately enter the Condition referenced in:
3.3.1.1	One or more <i>RPS instrumentation</i> Functions with RPS trip capability not maintained.	Table 3.3.1.1-1 for the associated Function.
3.3.1.4	One or more <i>NMS instrumentation</i> Functions with NMS trip capability not maintained.	Table 3.3.1.4-1 for the associated Function.
3.3.1.5	One or more <i>NMS actuation</i> Functions with NMS actuation capability not maintained.	Table 3.3.1.5-1 for the associated actuation Function.
3.3.6.1	One or more <i>MSIV instrumentation</i> functions with MSIV isolation capability not maintained.	Table 3.3.6.1-1 for the associated Function.
3.3.6.3	One or more <i>isolation instrumentation</i> functions with isolation capability not maintained.	Table 3.3.6.3-1 for the associated Function.
3.3.6.4	Isolation actuation capability not maintained.	Table 3.3.6.4-1 for the associated <i>actuation</i> Function.
3.3.7.1	One or more <i>CRHAVS instrumentation</i> functions with CRHAVS actuation capability not maintained.	Table 3.3.7.1-1 for the associated Function.

The conditions referenced by Required Action B.1 for the other listed LCOs (3.3.1.1, 3.3.6.1, 3.3.6.2, and 3.3.6.3) specify actions that are appropriate for the condition of the instrumentation and result in the unit being placed in an operating mode or condition in which the affected functions are not required or the associated system or component being declared inoperable. The times to perform these actions are the standard completion times used throughout the GTS and are consistent with STS guidance. GTS shutdown actions allow for shutting down the plant in a controlled and orderly manner and within the capability of systems used for unit shutdown and cooldown. Declaring a supported component inoperable is acceptable because the associated GTS Actions specify appropriate limitations on unit operation. Therefore, these actions are acceptable.

16.2.6.3.2.2 ECCS and ICS Functions for Required Instrumentation Channels and ECCS, ICS, and MSIV Functions for Required Actuation Divisions

In the specified conditions listed in Table 16-5 (either “Required Action and Associated Completion Time of Condition A not met,” “one or more functions with actuation capability not maintained,” or “one or more functions with two or more actuation divisions inoperable”), Required Action B.1 requires immediately declaring inoperable the affected components, actuation devices, or trains, as appropriate, for the ECCS and ICS instrumentation functions, and for the ECCS, ICS, and MSIV actuation functions. The staff added the italicized words to clarify the context of each condition and action.

Table 16-5. Summary of Actions for the Condition of Required Action and Associated Completion Time of Condition A Not Met, Functional Capability Not Maintained, or Two or More Actuation Divisions Inoperable, for ECCS and ICS Instrumentation Functions, and ECCS, ICS, and MSIV Actuation Functions.

LCO:	Condition B - Required Action and associated Completion Time of Condition A not met.	Required Action B.1 and associated Completion Time:
	<u>OR:</u>	
3.3.5.1	One or more <i>ECCS instrumentation</i> functions with ECCS actuation capability not maintained.	Immediately declare affected ECCS components inoperable.
3.3.5.2	One or more <i>ECCS actuation</i> functions with two or more required <i>ECCS</i> actuation divisions inoperable.	Immediately declare affected <i>ECCS</i> actuation device(s) inoperable.
3.3.5.3	One or more <i>ICS instrumentation</i> functions with ICS actuation capability not maintained.	Immediately declare ICS trains inoperable.
3.3.5.4	One or more <i>ICS actuation</i> functions with ICS actuation capability not maintained.	Immediately declare affected <i>ICS</i> actuation device(s) inoperable.
3.3.6.2	MSIV actuation capability not maintained.	Immediately declare affected <i>MSIV</i> actuation device(s) inoperable.

The actions for loss of ECCS, ICS, and MSIV actuation capability, and the action for an ECCS actuation function that has two or more required *ECCS* actuation divisions inoperable, are appropriate because declaring a supported component inoperable requires entering the associated GTS actions. These actions, which are specified by GTS 3.5.1, 3.5.2, 3.5.3, 3.5.4, and 3.6.1.3, provide appropriate limitations on unit operation. Therefore, Required Action B.1 for each of the listed conditions is acceptable.

16.2.6.3.2.2.3 RPS Functions for Required Actuation Divisions

GTS 3.3.1.2, "RPS Actuation," specifies an Action B with the unit in Mode 1 or 2 and an Action C with the unit in Mode 6, as shown in Table 16-6. These actions for loss of RPS actuation capability are appropriate for the condition of the instrumentation and result in the unit being placed in an operating mode or condition in which the affected actuation Function is not required. The times to perform these actions are the standard completion times used throughout the GTS and are consistent with STS guidance. GTS shutdown actions allow for shutting down the plant in a controlled and orderly manner within the capability of systems used for unit shutdown and cooldown. Therefore, Required Actions B.1 and C.1 for GTS 3.3.1.2 are acceptable.

Table 16-6. Summary of Actions for the Condition of Required Action and Associated Completion Time of Condition A Not Met, or Automatic Actuation Capability Not Maintained for RPS Actuation Function.

LCO:	Condition:	Required Action:	Completion Time:
3.3.1.2	<p>B. Required Action and associated Completion Time of Condition A not met in Mode 1 or 2.</p> <p><u>OR</u></p> <p>RPS automatic actuation capability not maintained in Mode 1 or 2.</p>	B.1 Be in Mode 3.	12 hours
3.3.1.2	<p>C. Required Action and associated Completion Time of Condition A not met in Mode 6.</p> <p><u>OR</u></p> <p>RPS automatic actuation capability not maintained in Mode 6.</p>	C.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

16.2.6.3.2.2.4 CRHAVS Actuation Function for Required Actuation Divisions

GTS 3.3.7.2, “CRHAVS Actuation,” specifies Action B for the condition of “Required Action and Associated Completion Time of Condition A not met” or “CRHAVS actuation capability not maintained.” The associated required actions specify that either of the following actions should be taken immediately: (1) isolating the CRHA boundary (B.1.1), placing (running) the operable (standby) CRHAVS train in isolation mode (B.1.2), and declaring the remaining (primary) CRHAVS train inoperable (B.1.3) or (2) declaring affected actuation devices inoperable (B.2). These required actions are acceptable because they accomplish the required CRHAVS actuation and CRHA isolation and impose a 7-day limit on unit operation (GTS 3.7.2, Action C), or they result in the unit being placed in a condition in which GTS 3.3.7.2 does not apply, in accordance with GTS 3.7.2, Actions E or F. (See previous discussion of GTS 3.3.7.1, Action B.)

The main control room temperature - high CRHAVS instrumentation function, which de-energizes the main control room (MCR) N-DCIS electrical loads in the event that the MCR air temperature reaches the actuation temperature setting is addressed in GTS 3.7.2 through SR 3.7.2.6 (perform channel calibration of MCR temperature instrumentation channels) instead of GTS Table 3.3.7.1-1. Therefore, were one or more of the three required channels for this instrumentation function inoperable, SR 3.7.2.6 would be considered not met, and by SR 3.0.2, LCO 3.7.2 would also be considered not met. Thus the action requirements of GTS 3.7.2 would apply. Since GTS 3.7.2 specifies no actions condition corresponding to an inoperable channel of this instrumentation function, by LCO 3.0.3, the unit would be required to exit the mode of applicability for GTS 3.7.2.

The corresponding actuation function is addressed by GTS SR 3.3.7.2.1 (perform LSFT on each required division) and SR 3.7.2.5 (verify de-energization of the MCR N-DCIS electrical loads on

an actual or simulated initiation signal). Were SR 3.7.2.5 not met, the above discussion would apply, and the unit would be required to exit the mode of applicability for GTS 3.7.2. Were SR 3.3.7.2.1 not met, then the action requirements of GTS 3.3.7.2 would apply according to the number of inoperable divisions for this actuation function. The action requirements for one or more inoperable channels or divisions for the N-DCIS de-energization function are more restrictive than the actions specified for the other CRHAVS instrumentation functions specified in Table 3.3.7.1-1. These actions are acceptable because they require placing the unit outside the applicable modes of GTS 3.3.7.1, GTS 3.3.7.2, and GTS 3.7.2 within an acceptable time period, consistent with the STS.

16.2.6.3.3 Actions for Functions with Two Instrumentation Channels

The following five LCOs require just two instrumentation channels for each required function:

- 3.3.1.3, “RPS Manual Actuation”
- 3.3.1.6, “SRNM Instrumentation”
- 3.3.2.1, “Control Rod Block (CRB) Instrumentation”
- 3.3.3.1, “Remote Shutdown System (RSS)”
- 3.3.3.2, “Post-Accident Monitoring (PAM) Instrumentation”

RAI 16.2-190 The staff asked the applicant to revise the treatment of GTS 3.3.3.2 for PAM functions, so that GTS 3.3.3.2 is a required part of the GTS and not a COL item in DCD Tier 2, Section 16.0, Table 16.0-1-A, as described in Section 16.2.6.1 of this report. The staff also requested that the applicant revise the actions of GTS 3.3.3.2 to be consistent with the BWR/6 STS 3.3.3.1 actions, which require placing the unit in Mode 3 within 12 hours if two required channels of certain PAM functions are inoperable for more than 7 days. In response, GEH stated it will revise the actions of GTS 3.3.3.2 and associated bases to be consistent with the STS. The staff reviewed the markup of the affected pages in the GTS and bases and found them to be acceptable. Therefore, RAI 16.2-190 is resolved. Section 16.2.6.1 of this report describes the resolution of the balance of the issues in this RAI.

The specified actions for the listed LCOs are appropriate to the design of each function's instrumentation channels and are consistent with the STS actions for equivalent instrumentation systems. Therefore, the action requirements for functions with two channels are acceptable.

16.2.6.3.4 Actions for GTS 3.3.4.1, “Reactor Coolant System (RCS) Leakage Detection Instrumentation”

LCO 3.3.4.1 requires the following RCS leakage detection instrumentation to be operable in Modes 1, 2, 3, and 4:

- Drywell floor drain high-conductivity waste (HCW) sump monitoring system
- Particulate channel of the drywell fission product monitoring system
- Drywell air coolers condensate flow monitoring system

This LCO is consistent with the corresponding STS LCO 3.4.7, “RCS Leakage Detection Instrumentation,” except for the following differences:

- The STS specify a drywell floor drain sump monitoring system, not an “HCW” drywell floor drain sump monitoring system.

- The STS specify either a particulate channel or a gaseous channel of the drywell atmospheric monitoring system.
- The STS specify a drywell air cooler condensate flow rate monitoring system as optional.

The following addresses these differences and the associated LCO actions for RCSLD instrumentation. GTS 3.3.4.1, "RCS Leakage Detection Instrumentation," and GTS 3.4.2, "RCS Operational Leakage," address Position C.9 of RG 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," issued May 1973. The staff sent the applicant RAIs 16.2-1 and 16.2-4 regarding the RCSLD instrumentation.

RAI 16.2-1 In RAI 16.2-1, the staff stated that NRC Information Notice 2005-24, "Nonconservatism in Leakage Detection Sensitivity," indicated that the containment radiation gaseous monitors might not be able to detect RCS leakage of 3.8 liters per minute (L/min) (1 gallon per minute [gpm]) within 1 hour. This finding was based on the experiences of operating reactors using fuel with improved integrity. DCD Tier 2, Section 11.5.3.2.12 indicates that the gaseous radiation monitor, which is used as one of the two monitors for the drywell fission product monitoring system in LCO 3.3.4.1(b), is able to detect 3.8 L/min (1 gpm) within 1 hour. In response, the applicant proposed to delete the gaseous radiation monitor from GTS 3.3.4.1. The airborne particulate radiation monitor remains as the drywell fission product monitoring system. Even without the gaseous radiation monitor, the ESBWR design satisfies RG 1.45, Regulatory Position C.3, by providing three RCS leakage detection methods - the drywell floor drain HCW sump monitoring system, the drywell fission product (particulate) monitoring system, and the drywell air coolers condensate flow monitoring system. The staff finds the applicant's response acceptable and confirmed that Revision 3 of GTS 3.3.4.1 included the changes.

In RAI 16.2-1, the staff also asked the applicant to address the procedures to convert the monitored parameters into a common leakage rate equivalent. RAI 5.2-4 also included this request. RAIs 16.2-1 and 5.2-4 were tracked as open items in the SER with open items. DCD Tier 2, Revision 9, Section 5.2.5.9, which includes COL Information Item 5.2-2-A, states the following:

The licensee is responsible for the development of a procedure to convert different parameter indications for identified and unidentified leakage common leak rate equivalents (volumetric or mass flow) and leak rate rate-of-change values.

Based on this statement and COL Information Item 5.2-2-A, this issue of RAI 16.2-1 is resolved. Therefore, based on resolution of RAIs 5.2-4 and 16.2-4, as well as the applicant's response to RAI 16.2-1, and the above statement in the DCD, RAI 16.2-1 is resolved.

RAI 16.2-4 The staff found that GTS LCO 3.4.2, "RCS Operational Leakage," did not specify a limit on the increase in unidentified leakage over a set period. This is not consistent with STS LCO 3.4.5.d, which states that the increase in unidentified leakage within the previous 4-hour period in Mode 1 shall be less than or equal to 7.6 L/min (2 gpm).

Omitting this limit on the volumetric flow increase per hour may not satisfy 10 CFR 50.36, which requires an LCO for installed instrumentation that is used to detect, and indicate in the CR, a significant abnormal degradation of the RCPB. The staff asked the applicant to justify omission of an LCO for an unidentified leakage rate-of-change from ESBWR GTS 3.4.2. RAI 16.2-4 was

being tracked as an open item in the SER with open items. In response the applicant provided the following justification:

[The STS LCO 3.4.5.d] specifies a limit for an increase in unidentified leakage [over a set time period]; however, [the printed statement of this requirement is] bracketed in its entirety. [The brackets indicate] that incorporation of this LCO requirement is a plant-specific issue.

[This LCO requirement was prompted by Generic Letter (GL) 88-01, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping."] GL 88-01 applies to all BWR piping made of austenitic stainless steel that is susceptible to intergranular stress corrosion cracking (IGSCC)...According to DCD Section 5.2.3.4.1, the RCS piping is designed to avoid sensitization and susceptibility to IGSCC through the use of reduced carbon content material and process controls. During fabrication, solution heat treatment is used. During welding, heat input is controlled. Austenitic stainless steels...are not used in the ESBWR design.

Historically, good operator practice plays a role in the event of an anomaly in unidentified leakage. [The operators] regularly observe and record data, monitor trends in plant parameters and detect abnormal conditions during their shift.... [This provides] a means to alert the plant staff to a condition that warrants further scrutiny and assessment. For example, if [unidentified] leakage is observed to be more than the normal expected leakage, yet less than the 5 gpm [19 L/min] [TS] limit, the plant operators typically will be alerted to investigate, record, and track pertinent data, evaluate trends in the data and make an assessment of the cause for any change that could ultimately lead to a reactor shutdown to make a drywell entry to take further action to locate, assess and potentially repair the source of leakage.

Based on the applicant's justification that the ESBWR RCS piping is designed to avoid sensitization and susceptibility to IGSCC through the use of reduced carbon content material and process controls, the staff concludes that the requirement (from GL 88-01 relating to IGSCC) for an unidentified leakage rate-of-change limit may no longer be needed as an LCO in the GTS for ESBWR. However, as a compensatory measure, the staff has determined that operating procedures for monitoring, recording, and trending of unidentified leakage and for responding to unidentified leakage rate-of-change alarms are needed to manage low-level RCS leakage. Therefore, to ensure implementation of such compensatory measures, the staff concluded that the ESBWR DCD needed a COL information item asking the COL applicant to develop unidentified leakage operating procedures. In response to this issue, the applicant established COL Information Item 5.2-2-A in DCD Tier 2, Section 5.2.5.9 and Section 5.2.6 as the following:

The COL Applicant will include in its operating procedure development program:

- Procedures to convert different parameter indications for identified and unidentified leakage into common leak rate equivalents and leak rate rate-of-change values.
- Procedures for monitoring, recording, trending, determining the source(s) of leakage, and evaluating potential corrective action plans.

- Milestone for completing this category of operating procedures (Section 5.2.5.9).

Section 5.2.5.9 also states:

The licensee is responsible for the development of procedures for monitoring, recording, trending, determining the source(s) of leakage, and evaluating potential corrective action plans. An unidentified leakage rate-of-change alarm provides operators an early alert to initiate response actions prior to reaching the Technical Specifications limit.

Based on the establishment of this COL item, the staff concludes that unidentified leakage will be adequately addressed through appropriate operating procedures. For this reason, and because ESBWR RCS piping is designed to avoid sensitization and susceptibility to IGSCC, omitting an LCO on unidentified leakage rate-of-change from GTS 3.4.2 is acceptable. Therefore, RAI 16.2-4 is resolved. The staff requested additional information regarding RCSLD as discussed below.

RAI 16.2-3 In RAI 16.2-3, the staff asked the applicant to state the instrumentation to be used to determine total RCS operational leakage and explain why GTS 3.3.4.1 did not include this instrumentation, as required by 10 CFR 50.36. In response, the applicant stated that RG 1.45, Regulatory Position 1, in part, requires that the source of leakage be identifiable to the extent practical. RCPB leak detection and collection systems should be selected and designed such that leakage from identified sources is collected or otherwise isolated so that the flow rates are monitored separately from unidentified leakage and the total flow rate can be established and monitored. DCD Tier 2, Revision 9, Section 5.2.5, describes the systems for detecting both identified and unidentified RCS leakage. The total reactor coolant leakage rate consists of all identified and unidentified leakages that flow to the lower drywell floor drain and equipment drain sumps. The reactor coolant leakage rate limits for alarm annunciation are established at less than or equal to 95 L/min (25 gpm) from identified sources and 19 L/min (5 gpm) from unidentified sources. The instrumentation is designed to measure leakage rates from unidentified sources of 3.8 L/min (1 gpm) in 1 hour. There is no specific instrument for determining total leakage, and the operator has procedures for converting the monitored parameters into a common leakage rate equivalent to assist in determining that the leakage rate is within specified limits. Based on these conditions, the staff finds that the applicant's method for monitoring RCS operational leakage is acceptable because it meets the requirements of 10 CFR 50.36. Therefore, on the basis of this information, RAI 16.2-3 is resolved.

RAI 16.2-5 Proposed GTS 3.3.4.1, Required Action A.1, requires restoring an inoperable drywell floor drain HCW sump monitoring system to operable status within 30 days. In RAI 16.2-5, the staff requested that the applicant explain how GTS SR 3.4.2.1, "Verify RCS unidentified and total LEAKAGE are within limits," can be performed when the drywell floor drain HCW sump monitoring system is inoperable. In response, the applicant stated that alternative leak rate monitoring methods, such as manually pumping the drywell floor drain HCW sump or directly measuring the change in drywell floor drain HCW sump level, are available to quantitatively determine RCS unidentified leakage. The applicant considered manual leak rate measurements to be acceptable alternatives while the drain sump monitoring system is inoperable, provided that the alternative leak rate methodology is implemented using controlled procedures, is demonstrated to be accurate, and can be inspected. Based on these conditions, the staff finds the applicant's alternative method to determine RCS leakage acceptable. Therefore, on the basis of this information, RAI 16.2-5 is resolved.

RAI 16.2-6 Proposed GTS 3.3.4.1, Required Action B.1, calls for the analysis of drywell atmosphere once every 12 hours when the drywell fission product monitoring system particulate channel is inoperable. Corresponding STS 3.4.7, Required Action B.1, also calls for analysis of grab samples of the drywell atmosphere every 12 hours, but Required Action B.2 requires restoration of the drywell atmospheric monitoring system to operable status within 30 days. In RAI 16.2-6, the staff requested that the applicant explain the omission of this required action to restore operability. In response, the applicant stated that the STS 30-day restoration time is a bracketed option based on having just one remaining automatic leak detection instrument operable (i.e., the analysis of grab samples of the drywell atmosphere is one of two remaining methods of leak detection; only the other method is automatic). The ESBWR design provides a third RCS leak detection instrument, the drywell air coolers condensate flow monitoring system. If both the drywell fission product monitoring system particulate channel and the drywell air coolers condensate flow monitoring system become inoperable, then Action D requires that one of these monitoring systems be restored to operable status within 30 days, provided that drywell atmosphere sampling continues every 12 hours and the drywell floor drain HCW sump monitoring system is operable. If the only method available is analysis of grab samples, Required Action E.1 mandates the placement of the plant in hot shutdown within 12 hours. Thus, the action requirements of GTS 3.3.4.1, including the 30-day completion time to restore the particulate channel and the allowance to continue plant operation indefinitely, while taking grab samples as long as the other two automatic detection methods are operable, are consistent with the STS and therefore acceptable. In summary, the staff concludes that the response to RAI 16.2-6 is acceptable. Therefore, RAI 16.2-6 is resolved.

RAI 16.2-7 The staff requested that the applicant provide technical justification for not entering Mode 5 when in GTS 3.3.4.1, Condition E, which states that the required action and associated completion time of Condition A, B, C, or D are not met. Proposed Action E requires placing the unit in Mode 3 within 12 hours. Equivalent STS LCO 3.4.7, Action E, specifies that the unit be in Mode 3 within 12 hours and Mode 5 within 36 hours. The staff also asked the applicant to justify why it omitted entering LCO 3.0.3, which would require being in Mode 5 within 37 hours when all the required leakage detection systems are inoperable. The applicant proposed a required action to be in Mode 3 within 12 hours; however, equivalent STS LCO 3.4.7, Action F, specifies entering LCO 3.0.3 when all required leakage detection systems are inoperable.

In response, the applicant referenced public meetings that discussed end-state relaxation of specific TS. The applicant's response to RAI 16.0-7 was to include the basis for the RCS leakage detection instrumentation required actions. In that letter, the applicant stated that GTS 3.3.4.1 presents an end-state relaxation (i.e., to Mode 3) that TSTF-423-A does not address. However, given that RCS leakage continues to be monitored to ensure that it is within limits, in accordance with LCO 3.4.2, "RCS Operational Leakage," the risk of operation in Mode 3, in lieu of proceeding to Mode 5 (cold shutdown), is bounded by evaluations made with other risk-significant systems inoperable. As discussed in Section 16.2.0 of this report, under RAI 16.0-7, the applicant withdrew its proposal to adapt TSTF-423-A to the GTS and adopt modified end states, for which the staff had requested additional ESBWR-specific justification and implementation guidance. The applicant revised GTS 3.3.4.1, Action E, to require the unit to be placed in Mode 5 within 36 hours when either the required action and associated completion time of Condition A, B, C, or D are not met or all of the required leakage detection systems are inoperable. These changes are consistent with the STS. Therefore, RAI 16.2-7 is resolved.

Based on the above evaluation of responses to the staff's RAIs, the actions for GTS 3.3.4.1 are acceptable.

16.2.6.3.5 Actions for GTS 3.3.8.1, “Diverse Protection System”

The ESBWR design includes a DPS to address concerns regarding common-cause failure of microprocessor- or digital-based instrumentation systems. The following discusses DPS functions and design, and the DPS LCO action requirements.

DPS Functions

The “Background” section of the bases for GTS 3.3.8.1 states, “DPS provides a set of initiation logics that provide a diverse means to initiate certain engineered safety feature (ESF) functions using sensors, hardware and software that are separate from, and independent of, the primary ESF systems.” The ESF functions include core cooling provided by the GDCS using injection and equalizing valves, and the ADS using safety/relief valves (SRVs) and depressurization valves (DPVs). The initiating logic for the injection and ADS valves is based on a signal of reactor pressure vessel level - low, Level 1, using two-out-of-four sensor logic and two-out-of-three processing logic. If the DPS ECCS initiation signal persists for 10 seconds, the logic seals in and a DPS ECCS start signal is initiated. The GDCS equalizing subsystem DPS initiation is a manual function.

Manual initiation of ADS and the GDCS injection and equalizing subsystems requires operation of two switches, with each switch requiring two distinct operator actions. The manual initiation signal is based on two-out-of-two coincident logic processed by triply redundant processors.

The DPS also performs selected containment isolation functions as part of the diverse ESF function using two-out-of-four sensor logic and two-out-of-three processing logic. The containment isolation functions performed by DPS include closure of the RWCU/SDC isolation valves on a signal of reactor water cleanup/shutdown cooling system differential mass flow - high.

The DPS also opens cross-connect valves between the equipment storage pool and the isolation condenser/passive containment cooling system (IC/PCCS) inner expansion pools when a low-level condition is detected in either of the IC/PCCS inner expansion pools.

DPS Design

The DPS is triply redundant and is powered by three nonsafety-related 120–V ac uninterruptible power supply (UPS) load groups. Each DPS cabinet and the four DPS RMUs can perform their intended functions with power from just two of the three UPS load groups. The UPS are battery backed and have sufficient capacity to support the specified DPS functions. The DPS functions are based on four DPS sensors. For example, Functions 1.a and 2.a are based on four reactor vessel-level sensors. The analog signal from each sensor is measured independently by three separate analog-to-digital converters in a DPS RMU, which send three digital output signals to the triply redundant processors in the DPS cabinet. Each DPS processor takes the three digital signals associated with each sensor and produces a signal for comparison with the setpoint (in this case, reactor vessel level - low, Level 1). Each DPS processor performs a voting logic function. If at least two out of four signals satisfy the setpoint, the DPS processor outputs a trip signal to either two (for solenoid initiators) or three (for squib initiators) output logic devices (OLDs) in the RMUs. If the OLD receives at least two trip signals from the three DPS processors, it will actuate its associated load driver (discrete output switch), which is in a series actuation circuit, to power the end device initiator. All OLDs must actuate their associated discrete output switches to complete the circuit to power the end

device initiator. The LCOs for the end devices address the operability, action, and SRs for the end device initiators (either a solenoid or a squib).

DPS Actions

GTS 3.3.8.1, Action A, allows 30 days to restore an inoperable required DPS function to operable status. A DPS function is inoperable if a sensor, any component in the RMU or DPS cabinet, or any discrete output switch is inoperable. Since it is possible for the instrumentation that implements a required DPS function to withstand some component failures without losing functional capability, Action A is conservative. In Condition A, design features intended to mitigate digital protection system common-mode failures may not be available. The 30-day completion time is acceptable because the required safety-related actuator initiators will actuate the minimum number of components required to respond to the design-basis LOCA concurrent with any additional single failure. If the inoperable DPS function is not restored to operable status within 30 days, Action B requires placing the unit outside the applicability of the LCO within standard completion times, consistent with the STS. Therefore, the actions for GTS 3.3.8.1 are acceptable.

16.2.6.3.6 Other Requests for Additional Information Regarding Actions

RAI 16.2-134 The reduced safety system capability described by the condition “capability not maintained” describes multiple SSC failures, representing a loss of two or three required channels or divisions of instrumentation out of four installed channels or divisions. This condition would permit the plant to operate for up to 1 hour with one or more accident prevention or mitigation functions of safety-related SSCs not operable. This is not an acceptable remedial action allowance because a loss-of-function condition should require immediate action to initiate a unit shutdown, consistent with the STS for similar instrumentation functions. For this specified plant condition, therefore, the staff will only accept a required action to immediately exit the GTS Applicability or immediately enter GTS LCO 3.0.3. The staff asked the applicant to revise the required action and completion time accordingly. RAI 16.2-134 was being tracked as an open item in the SER with open items.

In response, the applicant proposed to revise the GTS Section 3.3 required actions and completion times for conditions describing the “capability not maintained” condition by removing the 1-hour restoration time before requiring a unit shutdown. As previously noted, the staff considers that a unit shutdown is the appropriate action upon discovery of a loss-of-function condition. Therefore, RAI 16.2-134 is resolved.

RAI 16.2-138 In ESBWR GTS Section 3.3.1.3, “Reactor Protection System Manual Actuation,” for the actions condition of “one or more channels inoperable,” the reduced functional capability of the degraded condition described represents a loss of one or both required channels of instrumentation for one or both manual actuation items. This condition would permit the unit to operate for up to 12 hours with a loss of all required safety system RPS manual actuation instrumentation. Additional information is needed to justify that the loss-of-function condition is a credible condition for which a temporary relaxation of the required design basis should be approved. The staff asked the applicant to justify its decision to allow operation with more than one inoperable channel in either or both manual actuation functions. RAI 16.2-138 was being tracked as an open item in the SER with open items.

In response, the applicant revised the GTS 3.3.1.3 action requirements to allow separate condition entry for each manual actuation scram function, instead of for each channel. (Note:

There are two channels for each of the two manual actuation scram functions; the two functions are “manual scram,” which uses two scram push buttons, and the “reactor mode switch - shutdown position,” which initiates a full scram when the reactor mode switch is placed in the shutdown position. Both channels in a function must be manually actuated for that function to initiate a scram.) This change enabled clarifications to the GTS 3.3.1.3 action requirements so that, in the event both functions are inoperable with one or more channels disabled, the operator must place the inoperable channels in trip immediately, which may cause a reactor scram. To avoid a reactor scram transient, if the unit is in Mode 1 or 2, the actions require the operator to shut down the unit to Mode 3 within 12 hours. If the unit is in Mode 6, the actions require the operator to immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. The staff finds that these revised action requirements upon loss of manual scram capability are acceptable because they require placing the unit outside the applicability of the LCO in a timely manner, consistent with the STS. Therefore, RAI 16.2-138 is resolved.

RAI 16.2-142 The proposed end state for RCS leakage detection instrumentation LCO 3.3.4.1; LCO 3.3.6.3, Table 3.3.6.3-1, Function 13 (feedwater isolation instrumentation); and LCO 3.3.6.4, Table 3.3.6.4-1, Functions 14 (feedwater isolation valves) and 15 (feedwater pump breakers) is Mode 3; whereas, these functions are applicable in Modes 1, 2, 3, and 4. The staff requested that the applicant add required actions to place the plant in Mode 5 as the GTS required end state. RAI 16.2-142 was being tracked as an open item in the SER with open items. DCD Tier 2, Revision 5, Chapters 16 and 16B included the requested changes. Therefore, RAI 16.2-142 is resolved.

RAI 16.2-143 The staff questioned the need for the actions table Note 1 in GTS 3.3.6.1 and 3.3.6.2 for the MSLI instrumentation channels and actuation divisions. This note states that “penetration flow paths may be unisolated intermittently under administrative controls.” In response, the applicant proposed to remove the note and associated bases from GTS 3.3.6.1 and 3.3.6.2 because the actions of these specifications do not require isolating any penetration flow paths. This note is appropriate for GTS 3.6.1.3 because the actions specify isolating penetration flow paths, including main steam line and main steam drain line containment penetrations. DCD, Revision 4 incorporated these changes. Therefore, RAI 16.2-143 is resolved.

RAI 16.2-162 The staff requested that the applicant clarify the action requirements of DCD, Revision 4, GTS 3.3.5.3, “Isolation Condenser System (ICS) Instrumentation,” and 3.3.7.1, “CRHAVS Instrumentation.” In response, GEH stated that it was changing Required Action A.1 for the condition of “one or more Functions with one required instrumentation channel inoperable,” from “verify instrumentation division in trip” to “restore required channel to operable status.” The applicant stated the following:

This change more accurately reflects the design function for SSLC/ESF instrument channels to fail “as-is” (i.e., not to the tripped state) and the SSLC/ESF design which does not provide a means to manually place an instrument division in trip [that is, a division of instrument channels in trip]. This will also provide consistency in use of “channel” in both the Condition and the associated Required Action.

GEH also stated that it was combining Condition B, “required action and associated completion time of Condition A not met,” and Condition C, “one or more Functions with ICS actuation capability not maintained,” since they specify the same required action. The applicant revised

Required Action B.1, which has a completion time of “immediately,” from “declare associated ICS trains inoperable” to “declare ICS trains inoperable.” GEH stated, “This change reflects the SSLC/ESF design where each divisional instrument channel supports the actuation logic in all divisionally actuated devices equally.” The applicant revised the bases to make clear that all four required ICS trains are to be declared inoperable. This requires entering GTS 3.5.4, “ICS - Operating,” Action B, which requires the unit to be placed in Mode 3 in 12 hours. GEH made similar changes to the action requirements of GTS 3.3.7.1, but superseded these changes in DCD, Revision 6. Sections 16.2.6.3.2.1.2, 16.2.6.3.2.2.1, and 16.2.6.3.2.2.4 of this SER discuss the staff evaluation of the action requirements for CRHAVS instrumentation and actuation logic functions.

The applicant also changed the action requirements of GTS 3.3.5.4, “ICS Actuation,” to state the following:

- Action A, for the condition of one or more functions with one required actuation division inoperable, “Restore required division to operable status.”
- Action B, for the condition of one or more functions with ICS actuation capability not maintained, “Declare affected actuation device(s) inoperable.”

The applicant explained the proposed wording in Action B, as follows:

Required Action B.1 requires the “affected actuation device(s)” rather than “associated ICS train” to be declared inoperable. The SSLC/ESF design does not initiate an ICS train with an associated actuation logic division. Rather, any two actuation divisions can actuate all ICS trains. Since actuation division load drivers (i.e., the individual mechanical component actuation “signals”) are within the actuation logic, it is possible for their inoperability to be appropriately addressed by declaring only the associated actuated device inoperable. This change provides assurance that the affected actuated components in any train are declared inoperable, requiring entry into the appropriate mechanical system specification (GTS 3.5.4).

For the reasons stated, the staff finds these changes to GTS 3.3.5.4 acceptable. GEH proposed similar changes to GTS 3.3.7.2, “CRHAVS Actuation,” but superseded these changes in DCD, Revision 6 with the addition of two actuation functions for the standby CRHAVS train. Sections 16.2.6.3.2.1.2, 16.2.6.3.2.2.1, and 16.2.6.3.2.2.4 of this report discuss the staff evaluation of the action requirements for CRHAVS instrumentation and actuation logic functions. Based on the actions for these specifications as presented in DCD, Revision 6, RAI 16.2-162 is resolved.

16.2.6.3.7 Summary Conclusion Regarding Instrumentation Actions

The specified actions are appropriate to the design of each instrumentation function and are consistent with the STS actions for equivalent instrumentation systems. Therefore, they are acceptable.

16.2.6.4 Instrumentation Surveillance Requirements

According to 10 CFR 50.36(d)(3), the SRs are “requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that

facility operation will be within safety limits, and that the limiting conditions for operation will be met.” For each instrumentation specification, and for each associated instrumentation function, appropriate SRs are to be performed within the specified frequency (test interval) and in accordance with SRs 3.0.1, 3.0.2, 3.0.3, and 3.0.4.

The following describes the five main types of SRs specified for instrumentation functions. Each type has an associated defined term, presented in all upper case letters in the GTS and bases.

16.2.6.4.1 Evaluation of Channel Check Surveillance Requirements

GTS Section 1.1 defines a channel check (denoted by “Ch Chk” in Table 16-7 of this report) as follows:

A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

The following GTS SRs specify the channel check for the listed category of instrumentation functions:

- SR 3.3.1.1.1 RPS Instrumentation
- SR 3.3.1.4.1 NMS Instrumentation
- SR 3.3.1.6.1 SRNM Instrumentation
- SR 3.3.1.6.3 SRNM Instrumentation
- SR 3.3.3.2.1 PAM Instrumentation
- SR 3.3.4.1.1 RCSLD Instrumentation
- SR 3.3.5.1.1 ECCS Instrumentation
- SR 3.3.5.3.1 ICS Instrumentation
- SR 3.3.6.1.1 MSIV Instrumentation
- SR 3.3.6.3.1 Isolation Instrumentation
- SR 3.3.7.1.1 CRHAVS Instrumentation
- SR 3.3.8.1.1 Diverse Protection System (DPS)
- SR 3.7.1.1 IC/PCCS Expansion Pool Level Instrumentation

The GTS specify a channel check only for suitable instrumentation functions. This is consistent with the STS and is acceptable. No channel check is specified for RSS instrumentation functions because the only RSS function required by LCO 3.3.3.1 is RPS manual trip, which is the only RSS function required for safe shutdown.

RAI 16.2-147 The staff requested that the applicant provide data to show that the self-test report meets the requirements of a channel check without performing the required comparison of the parameter. RAI 16.2-147 was being tracked as an open item in the SER with open items. In response, the applicant noted that the STS bases usually do not include details of methods

for performing surveillances and proposed to remove from GTS bases all discussions of the online self-diagnostic design feature as a means of accomplishing a channel check. Removing these discussions removes this inconsistency with the STS; therefore, RAI 16.2-147 is resolved. However, removing from the GTS bases all discussions of the online self-diagnostic design feature as a means of accomplishing a channel check does not enable the staff to complete its review of this feature within the scope of the ESBWR design certification.

In DCD, Revision 5, the applicant proposed a 24-hour frequency for a channel check in place of the typical 12-hour frequency specified in the STS. The GTS bases appear to justify this relaxation by crediting the capabilities of the online self-diagnostic design feature to automatically detect instrumentation failures and presumably initiate alarms to alert the CR staff.

However, as noted in Section 16.2.6.5 of this report in the discussion of the GEH response to RAI 16.2-145 S01, GEH revised the channel check SR frequencies to be consistent with the BWR/6 STS and removed language from the bases for the channel check SRs that credited the online self-diagnostic design feature as a means of accomplishing a channel check. However, the GTS bases retained the online self-diagnostic design feature as part of the basis for the channel check SR frequencies. For example, the bases for SR 3.3.1.1.1 in draft DCD Revision 6 stated the following:

The Frequency is based upon operating experience that demonstrates channel failure is rare and the self-diagnostic features that monitor the channels for proper operation. The Channel Checks every 12 hours supplement less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

Because the DCD includes insufficient design information for the staff to conclude that the capabilities of the self-diagnostic feature can be credited in the bases to help justify the 12-hour frequency, GEH removed the self-diagnostic feature capabilities from the bases for channel check SR frequencies. Section 16.2.6.4.2 of this report, regarding the resolution of RAI 16.2-145 S02, discusses this issue further. Therefore, because the GTS bases for channel check SR frequencies are identical to the STS bases, they are acceptable.

The staff considers the proposed channel check SRs acceptable because the GTS definition of channel check is the same as the STS definition. In addition, the proposed channel check SRs are specified for all suitable instrumentation functions at frequencies consistent with the STS.

16.2.6.4.2 Evaluation of Channel Functional Test Surveillance Requirements

GTS Section 1.1 defines a channel functional test (CFT) as the following:

A CHANNEL FUNCTIONAL TEST shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify OPERABILITY of all devices in the channel required for channel OPERABILITY. The CHANNEL FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total channel steps.

The bases for each instrumentation specification further describe what constitutes a CFT for the associated functions, and typically state, "A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function."

The following GTS SRs specify a CFT for the listed category of instrumentation functions:

- SR 3.3.1.1.2 RPS Instrumentation
- SR 3.3.1.3.1 RPS Manual Actuation - Manual Scram Function (7 days)
- SR 3.3.1.3.2 RPS Manual Actuation - Reactor Mode Switch - Shutdown Position Function (24 months)
- SR 3.3.1.4.3 NMS Instrumentation (7 days)
- SR 3.3.1.4.4 NMS Instrumentation
- SR 3.3.1.6.5 SRNM Instrumentation (7 days)
- SR 3.3.1.6.6 SRNM Instrumentation (31 days)
- SR 3.3.2.1.1 CRB Instrumentation
- SR 3.3.2.1.2 CRB Instrumentation
- SR 3.3.2.1.3 CRB Instrumentation
- SR 3.3.2.1.4 CRB Instrumentation
- SR 3.3.2.1.8 CRB Instrumentation
- SR 3.3.3.1.1 RSS
- SR 3.3.4.1.2 RCSLD Instrumentation
- SR 3.3.5.1.2 ECCS Instrumentation
- SR 3.3.5.3.2 ICS Instrumentation
- SR 3.3.6.1.2 MSIV Instrumentation
- SR 3.3.6.3.2 Isolation Instrumentation
- SR 3.3.7.1.2 CRHAVS Instrumentation
- SR 3.3.8.1.2 DPS
- SR 3.7.1.7 IC/PCCS Expansion Pool Level Instrumentation

The staff considers the proposed CFT SRs acceptable because the GTS definition of CFT is the same as the STS definition, and they are specified for all suitable instrumentation functions.

The GTS contains two other CFT SRs that are required to be met during Mode 6, with a 7-day frequency. The associated bases for SR 3.9.1.1 (CFT for refueling equipment interlocks) and SR 3.9.2.2 (CFT for refuel position one-rod/rod-pair-out interlock), respectively, state the following:

The 7 day Frequency for the refueling equipment interlocks is based on engineering judgment and is considered adequate in view of other indications of refueling interlocks and their associated input status that are available to plant operations personnel.

The 7 day Frequency for the refuel position one-rod/rod-pair-out interlock is considered adequate because of demonstrated circuit reliability, procedural

controls on control rod withdrawals, and visual and audible indications available in the CR to alert the operator of control rods not fully inserted.

The staff considers the bases for these CFT surveillance frequencies consistent with the STS for equivalent instrument functions. Therefore, they are acceptable. However, the staff requested additional information concerning CFT surveillances.

RAI 16.2-148 The staff requested that GEH provide data to demonstrate that the self-test report meets the requirements of a CFT without performing a test to inject a simulated or actual signal into the channel as close to the sensor as practicable to verify operability of all devices in the channel required for channel operability. RAI 16.2-148 was being tracked as an open item in the SER with open items. In response, GEH noted that the STS bases usually do not include details of methods for performing surveillances and proposed to remove from GTS bases all discussions of the online self-diagnostic design feature as a means of accomplishing a CFT. Removing these discussions removes this inconsistency with the STS. Therefore, RAI 16.2-148 is resolved.

However, removing from GTS bases all discussions of the online self-diagnostic design feature as a means of accomplishing a CFT does not enable the staff to complete its review of this feature within the scope of the ESBWR design certification.

In DCD, Revision 5, Chapter 16, GTS Section 3.3, the applicant proposed a 24-month frequency for CFTs, in place of the typically shorter frequencies, (e.g., 7 days or 92 days as specified in the STS). The GTS bases appeared to justify this relaxation by crediting the capabilities of the online self-diagnostic design feature to automatically detect instrumentation failures and presumably initiate alarms to alert the CR staff. However, as noted in Section 16.2.6.5 of this report in the discussion of the GEH response to RAI 16.2-145 S01, GEH revised the CFT SR frequencies to be consistent with the BWR/6 STS and removed language from the bases for the CFT SRs that credited the online self-diagnostic design feature as a means of accomplishing a CFT. However, the bases retained the online self-diagnostic design feature as part of the basis for the CFT SR frequencies. For example, the bases for SR 3.3.1.1.2 stated that, "The Frequency of 92 days is based on the reliability of the channels and the self-diagnostic features that monitor the channels for proper operation." Because of this, the staff requested additional information, as follows.

RAI 16.2-145 S02 Because of insufficient design information, the staff was unable to conclude that the capabilities of the self-diagnostic design feature can be credited in the bases to help justify the CFT and channel check SR frequencies. The staff also cannot conclude that, based solely on instrument reliability, the ESBWR instrumentation can use the BWR/6 CFT SR frequencies, since BWR/6 instrumentation channel reliability is supported by NRC-approved topical reports, which only apply to analog instrumentation systems used in BWR/6 and earlier BWR plant designs. For these reasons, the staff requested GEH to take the following actions:

- Remove references taking credit for the online self-diagnostic design feature from the bases for instrumentation SR frequencies for all channel checks and CFTs. The staff stated that it will accept a channel check SR frequency of 12 hours and a CFT SR frequency of 7 days based solely on the reliability of the ESBWR instrumentation channels.
- Revise the CFT SR frequencies of 92 days to 31 days, which the staff will accept based solely on the reliability of the ESBWR instrumentation channels.

In response, GEH proposed to revise the CFT SR frequencies to 31 days and to remove the language describing the online self-diagnostic design feature from the bases for channel checks and CFTs. DCD Revision 6 incorporated these changes. Therefore, RAI 16.2-145 S02 is resolved.

Based on consistency with the STS and resolution of the CFT-related RAIs, the staff finds the proposed CFT SRs acceptable.

16.2.6.4.3 Evaluation of Channel Calibration Surveillance Requirements

GTS Section 1.1 defines channel calibration (denoted by “Ch Cal” in Table 16-7 of this report) as the following:

A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds within the necessary range and accuracy to known values of the parameter that the channel monitors. The CHANNEL CALIBRATION shall encompass all devices in the channel required for channel OPERABILITY and the CHANNEL FUNCTIONAL TEST. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an in place qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping, or total channel steps.

This definition is identical to the STS definition and is acceptable. The GTS require performing a channel calibration on each required channel, consistent with Specification 5.5.11, “Setpoint Control Program (SCP),” except for instrumentation having no trip settings to initiate automatic actuation of safety systems. The channel calibration surveillances for such instrumentation are the following:

- SR 3.3.1.6.7 SRNM (used only for neutron monitoring in Modes 3, 4, 5, and 6)
- SR 3.3.3.2.2 PAM (CR indication of parameters used for assessing postaccident conditions)
- SR 3.3.4.1.3 RCS leakage detection

The GTS bases for each instrumentation channel calibration SR typically describe what constitutes a channel calibration for the associated instrumentation functions as follows, where the nominal trip set point final (NTSP_F) is as defined in the NRC-approved setpoint methodology, which is specified by the SCP:

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the required channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the required channel adjusted to the NTSP_F within the “as-left” tolerance to account for instrument drifts between successive calibrations consistent with the methods and assumptions required by the SCP.

The bases for RCS leakage detection instrumentation also state, “The calibration verifies the accuracy of the instrument string, including the instruments located inside the drywell.”

All channel calibration SRs specify a frequency of 24 months. The GTS bases for each instrumentation channel calibration SR justify this frequency as follows:

1. The bases for the following SRs state that “The [24-month] Frequency is based upon the assumption of a 24-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.”
 - SR 3.1.7.8 SLC accumulator level instrumentation channels
 - SR 3.3.1.1.3 RPS instrumentation channels
 - SR 3.3.1.4.6 NMS instrumentation channels
 - SR 3.3.5.1.3 ECCS instrumentation channels
 - SR 3.3.5.3.3 ICS instrumentation channels
 - SR 3.3.6.1.3 MSIV instrumentation channels
 - SR 3.3.6.3.3 Isolation instrumentation channels
 - SR 3.3.7.1.3 CRHAVS instrumentation channels
 - SR 3.3.8.1.3 DPS instrumentation channels
 - SR 3.7.1.11 IC/PCCS inner expansion pool level instrumentation channels (that support automatic opening of the inner expansion pool-to-equipment pool squib and pneumatic cross connect valves on a low level in either inner expansion pool)
 - SR 3.7.2.6 MCR temperature instrumentation channels
 - SR 3.7.6.6 Loss-of-feedwater-heating instrumentation channels
2. The bases for the following SR state that, “The 24-month Frequency considers the unit conditions required to perform the test, the ease of performing the test, and the likelihood of a change in the system or component status.”
 - SR 3.3.1.6.7 SRNM instrumentation channels (neutron monitoring only)
3. The bases for the following SR state that, “The 24-month Frequency is based on operating experience and consistency with the typical industry refueling cycles.”
 - SR 3.3.3.2.2 PAM instrumentation channels
4. The bases for the following SR state that, “The Frequency of 24 months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.”
 - SR 3.3.4.1.3 RCS leakage detection instrumentation channels
5. The bases for the following SR state that, “The 24 month Frequency was developed to coincide with the 24 month refueling interval because access to the vacuum breakers is required to perform the SR.” See discussion of RAI 16.2-47 in Section 16.2.9 of this report for further evaluation of the 24-month frequency for this SR.
 - SR 3.6.1.6.4 Wetwell-to-drywell vacuum breaker flow path isolation function instrumentation channels

The staff considers the frequencies and the bases for the frequencies of the various channel calibration surveillances to be consistent with the STS for equivalent instrument functions, and therefore, they are acceptable.

RAI 16.2-163 In the list of changes for DCD Chapter 16 between DCD Revision 3 and Revision 4, Item 92, in GTS 3.7.6, "Selected Control Rod Run-In (SCRRI) and Selected Rod Insert (SRI) Functions," the applicant added a channel calibration SR for the SCRRI and SRI instrumentation functions; however, the LCO did not explicitly state these functions. The staff asked the applicant in RAI 16.2-163 to explain why the LCO does not specify these instrumentation functions. In response, the applicant stated "support functions (e.g., instrumentation functions) are not required to be specified in the LCO to adequately address the necessary operability requirement." The applicant proposed bases changes to clarify that the SCRRI and SRI function is connected with the loss-of-feedwater-heating initiation signal (i.e., instrumentation function) and to "clearly define that the channel calibration is associated with the loss-of-feedwater-heating initiation signal (eliminating use of "function" for the initiation signal)...." In DCD, Revision 5, the applicant revised SR 3.7.6.6 and bases to explicitly require the performance of a channel calibration of the "loss-of-feedwater-heating instrumentation channels." These changes provided the requested clarifications to SR 3.7.6.6 and associated bases. Therefore, RAI 16.2-163 is resolved.

16.2.6.4.4 Evaluation of Response Time Surveillance Requirements

GTS Section 1.1 specifies the five response time (denoted by "Resp Time" in Table 16-7 of this report) definitions identified below. The bases for each instrumentation specification further describe what constitutes a response time test for the associated functions. An excerpt from each associated bases follows each definition.

16.2.6.4.4.1 ECCS Response Time

Definition: "The ECCS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ECCS initiation setpoint at the channel sensor until the ECCS equipment is capable of performing its safety function (i.e., the valves travel to their required positions, etc.). The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC."

SR Bases: ECCS instrumentation and actuation response time testing "ensures that the individual required channel (or actuation division) response times are less than or equal to the maximum values assumed in the accident analysis. The ECCS RESPONSE TIME acceptance criteria are included in DCD Section 15.2." The tests required by instrumentation SR 3.3.5.1.4 and actuation SR 3.3.5.2.2 overlap to ensure complete testing of instrument channels and actuation circuitry.

RAI 16.2-97 In response to RAI 16.2-97, the applicant stated that it had added response time testing of the ECCS actuation logic with SR 3.3.5.2.2, "Verify the ECCS RESPONSE TIME of each required division is within limits." In RAI 16.2-97 S01, the staff stated that it did not concur with the applicant's position that the GTS implicitly includes ADS and DPV timers because the bases for the ECCS response time surveillance do not clearly state that the surveillance includes testing of the timers. RAI 16.2-97 was being tracked as an open item in the SER with open items. In response, GEH stated that in DCD, Revision 4, it had revised the bases for the

ECCS response time surveillance to clarify that the scope of the surveillance includes timers. With this change, therefore, RAI 16.2-97 is resolved.

The proposed ECCS response time SRs are acceptable because of the resolution of RAI 16.2-97 and because they are consistent with the STS.

16.2.6.4.4.2 Isolation Condenser System Response Time

Definition: “The ISOLATION CONDENSER SYSTEM (ICS) RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ICS initiation setpoint at the channel sensor until the ICS equipment is capable of performing its safety function (i.e., the valves travel to their required positions, etc.). The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.”

SR Bases: ICS instrumentation and response time testing “ensures that the individual required channel (or actuation division) response times are less than or equal to the maximum values assumed in the accident analysis. The ICS RESPONSE TIME acceptance criteria are included in DCD Section 15.2.” The tests required by instrumentation SR 3.3.5.3.4 and actuation SR 3.3.5.4.2 overlap to ensure complete testing of instrument channels and actuation circuitry.

The proposed ICS response time SRs are acceptable because they are consistent with the STS.

16.2.6.4.4.3 Isolation System Response Time

Definition: “The ISOLATION SYSTEM RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its isolation initiation setpoint at the channel sensor until the isolation valves travel to their required positions. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.”

SR Bases: Response time testing for MSIV instrumentation channels and actuation circuitry and isolation system instrumentation channels and actuation circuitry “ensures that the individual required channel (or actuation division) response times are less than or equal to the maximum values assumed in the accident analysis. The ISOLATION SYSTEM RESPONSE TIME acceptance criteria are included in DCD Section 15.2.” The tests required by the following pairs of instrumentation and actuation SRs, respectively, overlap to ensure complete testing of instrumentation channels and actuation circuitry:

- SR 3.3.6.1.4 and SR 3.3.6.2.2
- SR 3.3.6.3.4 and SR 3.3.6.4.2

The instrument response times must be added to the associated isolation valve closure times to obtain the isolation system response time.

The proposed isolation system response time SRs are acceptable because they are consistent with the STS.

16.2.6.4.4.4 Reactor Protection System Response Time

Definition: “The REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.”

SR Bases: Response time testing for RPS instrumentation and actuation and NMS instrumentation and actuation “ensures that the individual required channel (or actuation division) response times are less than or equal to the maximum values assumed in the accident analysis. The RPS RESPONSE TIME acceptance criteria are included in DCD Section 15.2.” The tests required by the following pairs of instrumentation and actuation SRs, respectively, overlap to ensure complete testing of instrument channels and actuation circuitry:

- SR 3.3.1.1.4 and SR 3.3.1.2.2
- SR 3.3.1.4.8 and SR 3.3.1.5.2

The proposed RPS response time SRs are acceptable because they are consistent with the STS.

16.2.6.4.4.5 Control Room Habitability Area Heating, Ventilation, and Air Conditioning Subsystem Response Time

Definition: “The CONTROL ROOM HABITABILITY AREA (CRHA) HEATING, VENTILATION, AND AIR CONDITIONING (HVAC) SUBSYSTEM (CRHAVS) RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its CRHAVS initiation setpoint at the channel sensor until the CRHAVS equipment is capable of performing its safety function (i.e., the dampers travel to their required positions, fans start, etc). The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.”

SR Bases: “This SR ensures that the individual required division response times are less than or equal to the maximum values assumed in the accident analysis. The instrument response times must be added to the associated closure times to obtain the CRHAVS RESPONSE TIME. CRHAVS RESPONSE TIME acceptance criteria are included in DCD Section 15.2.” The testing required by instrumentation SR 3.3.7.1.4 and actuation SR 3.3.7.2.2 overlap to ensure complete testing of instrumentation channels and actuation divisions.

The proposed CRHAVS response time SRs are acceptable because they are consistent with the STS.

16.2.6.4.4.6 Combined License Item to Omit Response Time Testing for Selected Components

RAI 16.2-157 In DCD, Revision 4, Chapter 16B, the GTS bases for the RPS, ECCS, and isolation system instrumentation response time testing SRs describe conditions for exempting selected components from response time testing. Furthermore, the bases refer to two topical reports, which are enclosed in brackets: NEDO-32291-A, "System Analyses for the Elimination of Selected Response Time Testing Requirements," and NEDO-32291-A, Supplement 1, "System Analyses for the Elimination of Selected Response Time Testing Requirements." In RAI 16.2-157 the staff requested that GEH provide information that describes and justifies application of these topical reports to ESBWR instrumentation functions for each selected component. This request was being tracked as an open item in the SER with open items. In response, GEH indicated that the topical reports were intended as examples to support elimination of certain response time tests in the ESBWR by a COL applicant or holder. In place of these examples, GEH provided a bracketed discussion and a reviewer's note in the bases. DCD, Revision 5 moved all reviewers' notes in the GTS and bases to DCD Table 16.0-1-A and established a reviewer's note for every COL item. For each COL item regarding an optional allowance to exclude from response time testing (1) certain sensors or other instrumentation components or (2) certain portions of the actuation circuitry, Table 16.0-1-A provides the following reviewer's note:

Applicants or Licensees may remove brackets and adopt this provision by application of Specification 5.5.7, "Bases Control Program," after appropriate assessment and incorporation into the plant licensing basis of an NRC approved methodology evaluating sensor and instrumentation loop response time requirements. All implementation requirements of the NRC Safety Evaluation Report for the methodology must be addressed. This allowance is provided as a template for potential future assessments.

The bracketed discussions in the GTS bases for response time testing SRs for instrumentation sensor channels and actuation divisions, respectively, typically state the following:

[However, some sensors for Functions are allowed to be excluded from specific RPS RESPONSE TIME measurement if the conditions of Reference XX are satisfied. If these conditions are satisfied, sensor response time may be allocated based on either assumed design sensor response time or the manufacturer's stated design response time. When the requirements of Reference XX are not satisfied, sensor response time must be measured. Furthermore, measurement of the instrument loops response times is not required if the conditions of Reference XX are satisfied.]

[However, some portions of the RPS actuation circuitry are allowed to be excluded from specific RPS RESPONSE TIME measurement if the conditions of Reference XX are satisfied. Furthermore, measurement of the instrument loops response times is not required if the conditions of Reference XX are satisfied.]

The above changes resolved RAI 16.2-157 because they clearly explain that NRC approval is required to exclude some sensor and actuation components from response time testing for those COL applicants or holders choosing to implement this option in accordance with DCD Tier 2, Revision 9, Table 16.0-1-A, COL Items 3.3.1.1-2, 3.3.1.2-1, 3.3.1.4-2, 3.3.1.5-2, 3.3.5.1-

2, 3.3.5.2-1, 3.3.5.3-2, 3.3.5.4-1, 3.3.6.1-2, 3.3.6.2-1, 3.3.6.3-2, 3.3.6.4-1, 3.3.7.1-3, and 3.3.7.2-2.

16.2.6.4.4.7 Response Time Test Acceptance Criteria

RAI 16.2-158. The staff requested GEH to revise the bases for RPS, ECCS, and isolation system response time SRs by stating the actual reference to the document containing the required response time limits. RAI 16.2-158 was being tracked as an open item in the SER with open items. In response, GEH revised the bases with the correct reference - DCD Tier 2, Section 15.2. DCD Tier 2, Table 15.2-23, "Instrument Response Time Limits for RPS, ECCS, MSIV, ICS, CRHAVS and Isolation Functions," states the actual response time limit values. Because GEH made the requested changes to the bases for RPS, ECCS, and isolation system response time SRs, RAI 16.2-158 is resolved.

16.2.6.4.4.8 Response Time Test Surveillance Requirement Frequency

The response time test SR frequency of 24 months on a staggered test basis, for three channels or divisions, which applies to the RPS, ECCS, MSIV, ICS, CRHAVS, and isolation system functions, is consistent with the STS for equivalent instrument functions. The GTS bases for these sensor and actuation SRs typically state that the frequency of 24 months on a staggered test basis ensures that the required [sensor] channels associated with each division are alternately tested and that each required [actuation] division is alternately tested. Specifically, the bases state "The 24-month test Frequency is consistent with the refueling cycle and with operating experience that shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent." On this basis, the proposed response time test SR frequency of 24 months on a staggered test basis is acceptable.

16.2.6.4.5 Evaluation of Logic System Functional Test Surveillance Requirements

GTS Section 1.1 provides the following definition of a logic system functional test (LSFT):

A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all logic components required for OPERABILITY of a logic circuit, from as close to the sensor as practicable up to, but not including, the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.

This is consistent with the STS and is acceptable. The bases for each instrumentation actuation LSFT SR, as listed below, further describe what constitutes a LSFT for the associated functions, as follows:

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the

- RPS Actuation divisions, including the two-out-of-four function of the Trip Logic Unit (TLU), Output Logic Unit (OLU), and Load Drivers (LDs) for a specific division. (bases for SR 3.3.1.2.1)
- NMS automatic actuation divisions. (bases for SR 3.3.1.5.1)
- Required ECCS logic for a specific division. (bases for SR 3.3.5.2.1)

- Required ICS logic for a specific division. (bases for SR 3.3.5.4.1)
- MSIV actuation divisions, including the two-out-of-four function of the Trip Logic Unit (TLU), Output Logic Unit (OLU), and Load Drivers (LDs) for a specific division. (bases for SR 3.3.6.2.1)
- Isolation actuation divisions. (bases for SR 3.3.6.4.1)
- Required CRHAVS logic for a specific division. (bases for SR 3.3.7.2.1)
- DPS logic. (bases for SR 3.3.8.1.4)
- Required actuation logic for the IC/PCCS expansion pool-to-equipment pool cross-connect valves for a specific division. (bases for SR 3.7.1.12)

The bases also state that the “24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.” The bases for the frequency of 24 months for the RPS, NMS, ECCS, ICS, MSIV, isolation, and CRHAVS actuation LSFT SRs are consistent with the STS bases for equivalent instrument actuation functions. Therefore, the proposed LSFT SRs, frequency, and bases are acceptable.

16.2.6.4.6 Evaluation of Instrumentation Surveillance Requirements Performed on a Staggered Test Basis

Certain SRs, such as response time testing, are performed on a staggered test basis, which GTS Section 1.1 defines as the following:

A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during n Surveillance Frequency intervals, where n is the total number of systems, subsystems, channels, or other designated components in the associated function.

This is consistent with the STS definition and is acceptable.

RAIs 16.2-29, 16.2-150, and 16.2-151 In RAI 16.2-29, the staff requested that the applicant identify all GTS Section 3.3 required actions that allow indefinite continued operation with an inoperable instrumentation function channel, provided the action requirements are met. (This is permitted when the inoperable instrument channel or actuation division is placed in trip; see Section 16.2.6.3.2 of this report.) The staff asked the applicant to revise its original response to account for the replacement of the emergency breathing air system with the CRHAVS, as well as any other changes to the proposed instrumentation GTS made since August 2006. RAI 16.2-29 was being tracked as an open item in the SER with open items. The staff considered this item to be related also to the “N-2” proposal for instrumentation LCOs, which requires one division less than specified in the design, provided that the design contains four divisions and just two are necessary to maintain function. The staff prefers that the LCO require all four divisions to be operable and that the actions specify no restriction on continued operation when just one division is inoperable. The staff prefers this approach because it applies explicit TS control of the status and testing of all four divisions, even though TS would

impose no operational restriction when only one of four divisions is inoperable. Subsequent changes to instrumentation action requirements culminating in DCD Revision 6 clarified the functions for which a channel or division may be placed in trip. RAIs 16.2-150 and 16.2-151 also address the issue concerning the number of instrumentation channels or actuation divisions that LCOs should require to be operable. In these RAIs, the staff requested that the applicant base the staggered test surveillance frequencies for response time testing and actuation instrumentation LSFTs, respectively, on the number of divisions required to be operable by the LCO (three) instead of the number in the design (four). In response to RAIs 16.2-150 and 151, the applicant stated its preference of basing the frequency on four divisions to avoid testing multiple divisions in a single test interval. RAIs 16.2-150 and 16.2-151 were being tracked as Open Item 16.2-150 in the SER with open items (RAI 16.2-151 being included in RAI 16.2-150 for tracking purposes). In RAI 16.2-150 S01, the staff stated its position that the application of the staggered testing definition should define the number of divisions to be tested as the number required to be operable by the associated LCO, and not the number in the design, and that this definition should be based on 10 CFR 50.36(d)(3) (i.e., "SRs are requirements to assure...that LCOs will be met"). In response to RAI 16.2-150 S01, the applicant stated that it would revise the LSFT and response time testing surveillance frequencies by deleting the phrase "for four channels." Because this change will ensure that staggered testing intervals for each channel or division will be determined by the number of channels or divisions required by the LCO, the staff finds the change acceptable. Therefore, RAIs 16.2-150 and 16.2-151 are resolved.

In DCD, Revision 6, GEH removed the allowance for staggered testing from the 24-month SR frequency for LSFT SRs because it lacked a technical basis. Since this change will require more frequent performance of the LSFT on each actuation division, the staff finds it acceptable.

Based on the above evaluation of instrumentation SRs, the staff finds the SRs for instrumentation and actuation functions acceptable. Table 16-7 of this report lists the specified SRs and associated frequencies for each instrumentation function, as stated in GTS Revision 9.

Table 16-7. Summary of Instrumentation Surveillances.

GTS Specification	Surveillance Requirement Frequencies *STAGGERED TEST BASIS h—hours, d—days, m—months					
	Ch Chk	CFT	Ch Cal	*Response Time	LSFT	Other SR
3.1.7 Standby Liquid Control (SLC) System						
SLC System accumulator level instrumentation			24 m			
3.3.1.1 RPS Instrumentation						
1. NMS Input—SRNM	12 h	31 d				
2. NMS Input—APRM/OPRM	12 h	31 d				
3. Scram Accumulator Charging Water Header Pressure - Low-Low	12 h	31 d	24 m			
4. Reactor Vessel Steam Dome Pressure - High	12 h	31 d	24 m	24 m		
5. Reactor Vessel Water Level - Low, Level 3	12 h	31 d	24 m	24 m		
6. Reactor Vessel Water Level - High, Level 8	12 h	31 d	24 m	24 m		
7. MSIV—Closure (Per Steam Line)		31 d	24 m	24 m		

GTS Specification		Surveillance Requirement Frequencies *STAGGERED TEST BASIS h—hours, d—days, m—months				
Function	Ch Chk	CFT	Ch Cal	*Response Time	LSFT	Other SR
8. Drywell Pressure - High	12 h	31 d	24 m	24 m		
9. Suppression Pool Temperature - High	12 h	31 d	24 m	24 m		
10. Turbine Stop Valve Closure Trip		31 d	24 m	24 m		
11. Turbine Control Valve Fast Closure Trip Oil Pressure - Low	12 h	31 d	24 m	24 m		
12. Main Condenser Pressure - High	12 h	31 d	24 m	24 m		
13. Power Generation Bus Loss	12 h	31 d	24 m	24 m		
14. Feedwater Temperature Biased Simulated Thermal Power - High	12 h	31 d	24 m			
15. Simulated Thermal Power Biased Feedwater Temperature - High	12 h	31 d	24 m			
16. Simulated Thermal Power Biased Feedwater Temperature - Low	12 h	31 d	24 m			
3.3.1.2 RPS Actuation						
RPS Automatic Actuation				24 m	24 m	
3.3.1.3 RPS Manual Actuation						
1. Manual Scram		7 d				
2. Reactor Mode Switch - Shutdown Position		24 m				
3.3.1.4 NMS Instrumentation						
1.a. SRNM - Neutron Flux - Short Period	12 h	7 d	24 m	24 m		
1.b. SRNM - Inop		7 d				
2.a. APRM - Fixed Neutron Flux - High, Setdown	12 h	7 d	24 m	24 m		
# average core exposure	SR 3.3.1.4.5, Calibrate LPRM					# 750 MWD/T
2.b. APRM - APRM Simulated Thermal Power - High	12 h	31 d	24 m	24 m		
# average core exposure	SR 3.3.1.4.2, Calorimetric SR 3.3.1.4.5, Calibrate LPRM SR 3.3.1.4.7, Verify time constant within limit					7 d # 750 MWD/T 24 m
2.c. APRM - Fixed Neutron Flux - High	12 h	31 d	24 m	24 m		
# average core exposure	SR 3.3.1.4.2, Calorimetric SR 3.3.1.4.5, Calibrate LPRM					7 d # 750 MWD/T
2.d. APRM - Inop		31 d				
3. OPRM - Upscale		31 d	24 m	24 m		
	SR 3.3.1.4.9, Verify OPRM is not bypassed when thermal power is ≥ 25% RTP					24 m
3.3.1.5 NMS Automatic Actuation						
1. SRNM				24 m	24 m	
2. APRM				24 m	24 m	
3. OPRM				24 m	24 m	

GTS Specification		Surveillance Requirement Frequencies *STAGGERED TEST BASIS h—hours, d—days, m—months				
Function	Ch Chk	CFT	Ch Cal	*Response Time	LSFT	Other SR
3.3.1.6 SRNM Instrumentation (monitoring and indication functions only)						
1. SRNM Modes 3, 4, 5 **during Core Alterations	24 h	31 d	24 m			
	SR 3.3.1.6.4, Verify count rate is ≥ 3.0 cps					12 h** and 24 h
1. SRNM Mode 6 (may substitute movable detectors) **during Core Alterations	12 h	7 d	24 m			
	SR 3.3.1.6.2, Verify SRNM location SR 3.3.1.6.4, Verify count rate is ≥ 3.0 cps					12 h 12 h** and 24 h
3.3.2.1 Control Rod Block (CRB) Instrumentation						
1.a. Rod Control and Information System (RC&IS) - Automated Thermal Limit Monitor (ATLM) ^ SR 3.3.2.1.1 Note: Not required to be performed until one hour after Thermal Power is ≥ 30% RTP.		^31 d				
	SR 3.3.2.1.6, Verify required ATLM channels are not bypassed when Thermal Power is ≥ 30% RTP					24 m
1.b. RC&IS - Rod Worth Minimizer (RWM) ^ SR 3.3.2.1.2 Note: Not required to be performed until one hour after any control rod is withdrawn in Mode 2. ** SR 3.3.2.1.4 Note: Not required to be performed until one hour after Thermal Power is ≤ 10% RTP.		^31 d **31 d				
	SR 3.3.2.1.5, Verify required RWM channels are not bypassed when Thermal Power is ≤ 10% RTP. SR 3.3.2.1.9, Verify the bypassing and movement of control rods required to be bypassed in the Rod Action Control Subsystem (RACS) cabinets by a second licensed operator or other qualified member of the technical staff.					24 m Prior to and during the movement of control rods bypassed in RACS
1.c. Multi-Channel Rod Block Monitor (MRBM) ^ SR 3.3.2.1.4 Note: Not required to be performed until one hour after Thermal Power is ≥ 30% RTP.		^31 d				
	SR 3.3.2.1.7, Verify required MRBM channels are not bypassed when Thermal Power is ≥ 30% RTP.					24 m
2. Reactor Mode Switch - Shutdown Position ^ SR 3.3.2.1.8 Note: Not required to be performed until one hour after reactor mode switch is in shutdown position.		^24 m				
3.3.3.1 Remote Shutdown System (RSS)						
RPS Division 1 & 2 Manual Scram Switches		24 m				
3.3.3.2 Post-Accident Monitoring (PAM) Instrumentation						
Each Type A, B, and C PAM Instrumentation Function	31 d		24 m			
3.3.4.1 Reactor Coolant System (RCS) Leakage Detection Instrumentation						
a. Drywell Floor Drain HCW Sump Monitoring System	12 h	31 d	24 m			

GTS Specification		Surveillance Requirement Frequencies *STAGGERED TEST BASIS h–hours, d–days, m–months					
Function		Ch Chk	CFT	Ch Cal	*Response Time	LSFT	Other SR
b.	Particulate Channel of the Drywell Fission Product Monitoring System	12 h	31 d	24 m			
c.	Drywell Air Coolers Condensate Flow Monitoring System	12 h	31 d	24 m			
3.3.5.1 ECCS Instrumentation							
1.	Reactor Vessel Water Level - Low, Level 1	12 h	31 d	24 m	24 m		
2.	Reactor Vessel Water Level - Low, Level 0.5	12 h	31 d	24 m	24 m		
3.	Drywell Pressure - High	12 h	31 d	24 m	24 m		
3.3.5.2 ECCS Actuation							
1.	ADS				24 m	24 m	
2.	GDCS Injection Lines				24 m	24 m	
3.	GDCS Equalizing Lines				24 m	24 m	
4.	Standby Liquid Control (SLC)				24 m	24 m	
3.3.5.3 ICS Instrumentation							
1.	Reactor Vessel Steam Dome Pressure - High	12 h	31 d	24 m	24 m		
2.	Reactor Vessel Water Level - Low, Level 2	12 h	31 d	24 m	24 m		
3.	Reactor Vessel Water Level - Low, Level 1	12 h	31 d	24 m	24 m		
4.	MSIV - Closure		31 d	24 m	24 m		
5.	Power Generation Bus Loss	12 h	31 d	24 m	24 m		
6.	Condensate Return Valve - Open		31 d	24 m			
3.3.5.4 ICS Actuation							
1.	ICS Initiation Actuation				24 m	24 m	
2.	ICS Vent Actuation					24 m	
3.3.6.1 MSIV Instrumentation							
1.	Reactor Vessel Water Level - Low, Level 2	12 h	31 d	24 m	24 m		
2.	Reactor Vessel Water Level - Low, Level 1	12 h	31 d	24 m	24 m		
3.	Main Steam Line Pressure - Low	12 h	31 d	24 m	24 m		
4.	Main Steam Line Flow - High (Per Steam Line)	12 h	31 d	24 m	24 m		
5.	Condenser Pressure - High (Per Condenser)	12 h	31 d	24 m	24 m		
6.	Main Steam Tunnel Ambient Temperature - High	12 h	31 d	24 m	24 m		
7.	Main Steam Turbine Area Ambient Temperature - High	12 h	31 d	24 m	24 m		
3.3.6.2 MSIV Actuation							
MSIV [isolation] actuation					24 m	24 m	
3.3.6.3 Isolation Instrumentation							
1.	Reactor Vessel Water Level - Low, Level 2	12 h	31 d	24 m	24 m		

GTS Specification		Surveillance Requirement Frequencies *STAGGERED TEST BASIS h–hours, d–days, m–months					
Function		Ch Chk	CFT	Ch Cal	*Response Time	LSFT	Other SR
2.	Reactor Vessel Water Level - Low, Level 1	12 h	31 d	24 m	24 m		
3.	Drywell Pressure - High	12 h	31 d	24 m	24 m		
4.	Main Steam Tunnel Ambient Temperature - High	12 h	31 d	24 m	24 m		
5.	RWCU/SDC Differential Mass Flow - High (Per Subsystem)	12 h	31 d	24 m	24 m		
6.	Isolation Condenser Steam Line Flow - High (Per Isolation Condenser)	12 h	31 d	24 m	24 m		
7.	Isolation Condenser Condensate Return Line Flow - High (Per Isolation Condenser)	12 h	31 d	24 m	24 m		
8.	Isolation Condenser Pool Vent Discharge Radiation - High (Per Isolation Condenser)	12 h	31 d	24 m	24 m		
9.	Depressurization Valve - Open		31 d	24 m	24 m		
10.	Feedwater Line Differential Pressure - High	12 h	31 d	24 m	24 m		
11.	Reactor Building Exhaust Radiation - High	12 h	31 d	24 m	24 m		
12.	Drywell Water Level - High	12 h	31 d	24 m	24 m		
13.	Reactor Vessel Water Level Low - Level 0.5	12 h	31 d	24 m	24 m		
14.	Drywell Pressure - High-High	12 h	31 d	24 m	24 m		
15.	GDCS Pool Water Level - Low	12 h	31 d	24 m	24 m		
3.3.6.4 Isolation Actuation							
1.	Reactor Water Cleanup/Shutdown Cooling (RWCU/SDC) System Isolation (Modes 1, 2, 3, 4, 5, 6)				24 m	24 m	
1.	RWCU/SDC Isolation (Modes 5, 6)	SR 3.3.6.4.3, Perform a system functional test					24 m
2.	ICS Isolation				24 m	24 m	
3.	Process Radiation Monitoring System Isolation				24 m	24 m	
4.	Equipment and Floor Drain System Isolation				24 m	24 m	
5.	Containment Inerting System Isolation				24 m	24 m	
6.	Chilled Water System Isolation				24 m	24 m	
7.	Fuel and Auxiliary Pools Cooling System Process Isolation				24 m	24 m	
8.	Reactor Building Heating, Ventilation and Air Conditioning System Isolation				24 m	24 m	
9.	High Pressure Nitrogen Gas Supply System Isolation				24 m	24 m	
10.	Feedwater Isolation Valves Isolation				24 m	24 m	
		SR 3.3.6.4.3, Perform a system functional test					24 m

GTS Specification	Surveillance Requirement Frequencies *STAGGERED TEST BASIS h–hours, d–days, m–months					
Function	Ch Chk	CFT	Ch Cal	*Response Time	LSFT	Other SR
11. High Pressure Control Rod Drive Isolation				24 m	24 m	
	SR 3.3.6.4.3, Perform a system functional test					24 m
3.3.7.1 CRHAVS Instrumentation						
1. CR Air Intake Radiation - High-High	12 h	31 d	24 m	24 m		
2. Extended Loss of AC Power	12 h	31 d	24 m	24 m		
3. Emergency Filter Unit (EFU Discharge Flow - Low (primary train)	12 h	31 d	24 m	24 m		
4. EFU Outlet Radiation - High-High (primary train)	12 h	31 d	24 m	24 m		
3.3.7.2 CRHAVS Actuation						
CRHAVS Actuation				24 m	24 m	
3.3.8.1 Diverse Protection System (DPS)						
1.a ADS - Actuation, Reactor Vessel Level - Low, Level 1	12 h	31 d	24 m		24 m	
1.b ADS - Actuation, Drywell Pressure - High (Manual Actuation)	12 h	31 d	24 m		24 m	
2.a GDCS Injection Lines - Actuation, Reactor Vessel Level - Low, Level1	12 h	31 d	24 m		24 m	
2.b GDCS Injection Lines - Actuation, Drywell Pressure - High (Manual Actuation)	12 h	31 d	24 m		24 m	
3.a GDCS Equalizing Lines - Actuation, Reactor Vessel Level - Low (Manual Actuation)	12 h	31 d	24 m		24 m	
4.a RWCU/SDC System Lines - Isolation, RWCU/SDC System Differential Mass Flow - High	12 h	31 d	24 m		24 m	
5.a Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Expansion Pool-to-Equipment Pool Cross-Connect - Actuation, IC/PCCS Pool Level - Low	12 h	31 d	24 m		24 m	
3.6.1.6 Wetwell-to-Drywell Vacuum Breakers						
Vacuum breaker flow path isolation function			24 m			
	SR 3.6.1.6.5, Perform a system functional test					24 m
3.7.1 Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Pools						
IC/PCCS expansion pool level instrumentation channels	12 h	31 d	24 m			
IC/PCCS expansion pool-to-equipment pool cross-connect actuation logic divisions					24 m	
3.7.2 CRHAVS						
MCR temperature instrumentation channels			24 m			

GTS Specification	Surveillance Requirement Frequencies *STAGGERED TEST BASIS h–hours, d–days, m–months					
Function	Ch Chk	CFT	Ch Cal	*Response Time	LSFT	Other SR
3.7.6 Selected Control Rod Run-In (SCRRI) and Select Rod Insert (SRI) Functions						
Loss of feedwater-heating instrumentation channels			24 m			
	SR 3.7.6.3. Perform system functional test for the SCRRI function					24 m
	SR 3.7.6.4. Perform system functional test for the SRI function					24 m
3.9.1 Refueling Equipment Interlocks						
a. All-rods-in		7 d				
b. Refueling machine position		7 d				
c. Refueling machine fuel grapple hoist, fuel loaded		7 d				
d. Refueling machine auxiliary hoist, fuel loaded		7 d				
3.9.2 Refuel Position One-Rod/Rod-Pair-Out Interlock						
Mode switch refuel position one-rod/rod-pair-out interlock ^ SR 3.9.2.2 Note: Not required to be performed until one hour after any control rod is withdrawn.		^7 d				

16.2.6.5 Setpoint Methodology

DCD Tier 2, Revision 9, Section 7.1.3.1.3, “Q-DCIS Setpoint Methodology,” describes the considerations for determining instrumentation settings; these considerations are reflected in the setpoint methodology for ESBWR instrumentation settings. GEH submitted this methodology for staff review and approval as part of the ESBWR design certification in NEDE-33304P, “GEH ABWR/ESBWR Setpoint Methodology.” This was an update to NEDC-31336P-A, “General Electric Instrument Setpoint Methodology,” to address conformance with Regulatory Issue Summary (RIS) 2006-17, “NRC Staff Position on the Requirements of 10 CFR 50.36, ‘Technical Specifications,’ Regarding Limiting Safety System Settings During Periodic Testing and Calibration of Instrument Channels.” GEH submitted Revision 1 to NEDE-33304P, to incorporate changes based on the GEH responses to staff comments in RAI 7.1-86 and its supplement, as well as the GEH response to staff comments in RAI 7.1-102. GEH submitted Revision 4 to NEDE-33304P to incorporate changes based on the GEH responses to staff comments in RAI 7.1-141. See Section 7.1.4 of this report for a discussion of the staff’s review of the ESBWR instrumentation setpoint methodology and the resolution of related RAIs 7.1-86, 7.1-102, and 7.1-141.

Following is a summary of how issues related to the setpoint methodology affected the review of GTS channel calibration SRs and the presentation of instrumentation limiting safety system settings (LSSS) in the GTS to satisfy the requirements of 10 CFR 50.36(c)(1)(ii)(A).

In RAI 7.2-36, the staff requested that GEH clarify that the analytical limits, from which the instrumentation trip settings are determined, are based on the ESBWR accident analysis, and not on “typical analytical limits,” as implied by DCD Tier 2, Revision 1, Tables 7.2-2 and 7.2-3.

In response, and in DCD Revision 3, GEH provided the requested clarification. As described below, the staff subsequently sent GEH a supplement to this RAI.

RAI 16.2-25 The staff asked GEH to revise Revision 1 of the GTS instrumentation TS to adopt the NRC-approved version of TSTF-493, "Clarify Application of Setpoint Methodology for LSSS Functions." Once the staff approves this STS generic change, it will provide resolution of regulatory and technical issues regarding LSSS during periodic testing and calibration of instrument channels. In response GEH committed to address incorporation of TSTF-493 to the extent practicable, based on the ESBWR design and setpoint methodology, in a future revision of DCD Chapters 16 and 16B, following approval of TSTF-493 by the NRC. Based on this commitment, therefore, RAI 16.2-25 is resolved.

In DCD, Revision 2, GEH proposed to add a SCP specification to GTS Section 5.5 that would require use of an NRC-approved setpoint methodology to determine the various instrumentation setting acceptance criteria, which must be satisfied to meet channel calibration SRs, and which would be maintained in a Licensee-controlled document outside the TS. The proposed SCP specification also contained the technical content of STS instrumentation function table footnotes, which had been included in TSTF-493 to address performance of channel calibration SRs. In conjunction with the addition of a SCP specification, GEH revised the GTS instrumentation function tables to identify the instrumentation function analytical limits or design limits under the heading "setting basis," instead of stating the allowable values. In addition, GEH revised the channel calibration SRs to reference the SCP specification (this also included channel calibration SRs in GTS sections other than Section 3.3). These changes reflected ongoing discussions between the NRC and the TSTF regarding TSTF-493; DCD Revision 3 retained these changes.

Before receipt of DCD, Revision 2, however, the staff had sent GEH RAI 7.2-36 S01 which requested that GEH provide the following information for each instrumentation function:

1. Documentation, with example calculations, of the methodology for determining the limiting and nominal trip setpoints (LTSP and NTSP), acceptable as-found and as-left settings, and the analytical limit or other limiting design values, including the sources of these values.
2. A statement as to whether the instrumentation setting is for a variable on which a SL has been placed (SL-related settings).
3. A description of whether and how GEH will adopt in the ESBWR GTS the setpoint-related TS provisions for SL-related instrumentation functions, contained in a letter from the NRC to the Nuclear Energy Institute (NEI) (ADAMS Accession No. ML052500004). The letter includes a description of how as-found settings will be evaluated during surveillances, and the controls to ensure that the instrument as-left setting at the conclusion of the surveillance is consistent with the setpoint methodology.
4. For non-SL-related instrumentation, a description of the measures to be taken to ensure that the instrument channel is capable of performing its specified safety functions in accordance with applicable design requirements and associated analyses; this will include a description of the controls to ensure that the instrument as-left setting at the conclusion of the surveillance is consistent with the setpoint methodology and the corrective action process for restoring channels to operable status.

In response, GEH (1) stated that ESBWR setpoints are calculated by NEDC-31336P-A, the latest NRC-approved General Electric setpoint methodology, and described its use, with sample calculations; (2) identified all SL-related instrumentation functions; (3) committed to adopt the latest NRC guidance regarding the additional TS provisions for instrumentation settings; and (4) provided the information requested regarding non-SL-related instrumentation functions. As noted above, GEH proposed an updated setpoint methodology in NEDE-33304P. Therefore, regarding the response to Item (1), the staff concluded that GEH intends to calculate instrumentation settings using NEDE-33304P, once approved by the staff, and not NEDC-31336P-A. Therefore, RAI 7.2-36 is resolved based on the information in the applicant's responses. In addition, the staff transferred resolution tracking of SCP specification issues to RAI 16.2-156 and setpoint methodology issues to RAI 7.1-102.

In response to RAI 7.2-36 S01, GEH also stated that it would specify the AV in the GTS for each instrumentation function and remove the proposed SCP specification. DCD, Revision 4, however, did not include these changes.

In DCD, Revision 5, GEH replaced the "setting basis" with the AV in the GTS for each instrumentation function according to its follow-up response to RAI 7.2-36 S01. However, GEH retained the SCP specification (with changes based on its response to RAI 16.2-156 S01) to satisfy the provisions of 10 CFR 50.36(c)(1)(ii)(A). Stating AVs in the TS is potentially less burdensome than stating NTSPs because AVs are anticipated to change much less frequently than NTSPs and consequently could result in fewer setpoint-related license amendments over the life of the facility. However, the staff took the position in RIS 2006-17 that the NTSP (equivalent to ESBWR NTSP_F) values are the LSSS required to be included in the TS by 10 CFR 50.36(c)(1)(ii)(A). If an SCP specification is written with suitable compliance language so that it has sufficient regulatory force, then the staff may conclude that the GTS satisfy 10 CFR 50.36(c)(1)(ii)(A), even though the LSSS values (NTSP values) would be maintained in a Licensee-controlled document outside the TS.

RAI 16.2-156 In RAI 16.2-156, the staff requested GEH to revise the GTS LCO instrumentation function tables (as stated in DCD, Revision 4) to include the type of instrumentation setting values that are consistent with the ABWR/ESBWR setpoint methodology. RAI 16.2-156 was being tracked as an open item in the SER with open items. In response, GEH stated that it had previously changed the GTS to state the AVs in its follow-up response to RAI 7.2-36 S01.

The staff decided that 10 CFR 50.36(c)(1)(ii)(A) could allow the NTSP_F values to be maintained in a Licensee-controlled document outside the TS, provided the SCP specification contained provisions ensuring adequate TS control of those values. Subsequently, the staff sent GEH RAI 16.2-156 S01 that described the necessary program provisions and included an example of an SCP specification acceptable to the staff. (Note: RAI 16.2-156 S01 superseded RAI 7.2-36 regarding SCP specification issues.)

In response, GEH moved some of the provisions in the staff's example SCP specification to a reviewer's note in DCD Section 16.0. A reviewer's note states any necessary conditions for site-specific implementation of a bracketed TS provision. As noted in Section 16.2.0 of this report, GEH provided a reviewer's note in DCD Table 16.0-1-A for every COL item in the GTS and bases. The FSAR associated with a COL will not retain the reviewer's notes, as well as the listing of COL items. Because of this, the staff considered the applicant's decision to place some of the provisions of the proposed SCP in a reviewer's note to be unacceptable.

In RAI 16.2-156 S02, the staff requested that GEH revise its proposed SCP specification to conform to a second example SCP specification, in which the staff had incorporated some but not all of the GEH suggestions. In response, GEH incorporated all of the provisions in the staff's second example SCP, except for those previously relegated to the reviewer's note.

In RAI 16.2-156 S03, the staff proposed that (1) the contested provisions be retained as bracketed items in the SCP specification and (2) the reviewer's note state that a COL applicant may choose to either remove the brackets or incorporate the bracketed information in the NRC-approved setpoint methodology document. The staff also insisted that Licensees should trend as-found settings for each instrument channel regardless of whether they are less conservative than the predetermined as-found tolerance (AFT). In response, GEH adopted the staff's proposal except for the creation of two COL items to be included in DCD Table 16.0-1-A. The applicant's proposal retained the provision regarding the comparison of the as-found setting with the NTSP_F in the reviewer's note for GTS 5.5.11, which specifies that this provision be incorporated into the NRC-approved setpoint methodology. This is acceptable to the staff because the SCP specification requires (1) calculating the AFT and the as-left tolerance (ALT) in conformance with the NRC-approved setpoint methodology and (2) comparing the as-found setting with the previous as-left setting or the NTSP_F during channel calibration surveillance. The applicant's proposal also moved the provision regarding trending and evaluating the difference between the as-found setting and the previous as-left setting or the NTSP_F from the reviewer's note to the SCP specification. The staff finds this is acceptable because specifying this provision in GTS 5.5.11 will ensure that the instrument channel is functioning in accordance with its design basis. With these revisions, the staff concludes that GTS 5.5.11 satisfies the LSSS requirements of 10 CFR 50.36(c)(1)(ii)(A). Therefore, RAI 16.2-156 is resolved.

DC/COL-ISG-8 In its letter dated February 24, 2009, regarding DC/COL-ISG-8, GEH proposed deleting all GTS bracketed placeholders for AVs because AVs would be determined and maintained in a document outside the TS in accordance with the SCP specification. (See Section 16.2.0 of this report for additional information concerning completion of COL information.) Based on the resolution of RAI 16.2-156, this change is acceptable because the SCP specification will ensure adequate TS control of the AVs, as well as the other instrumentation setting criteria.

RAI 16.2-145 In RAI 16.2-145, the staff stated that instrumentation channel operability that is based on AVs, predefined AFT bands, and ALT bands, as specified in the GTS for the ESBWR, is applicable only to analog protection systems using bistables. For the ESBWR digital protection systems, setpoints are controlled in the GTS. The GTS require that the NTSP, embedded in the digital protection system, be equal to or conservative with respect to the LSSS. The staff requested that GEH provide documentation to show that the GTS will require surveillances to verify operability of the critical functions using (1) internal diagnostic methods that can monitor the "health" of different processors/memory boards and perform software checks to ensure that the proper software is executing and (2) power-up tests (e.g., random access memory; erasable, programmable read-only memory) and error checking on the data links, as well as tests by a transmitting channel, to ascertain that the transmitted signal is properly received by the receiving channels during the CFT. The staff requested this information to understand how the proposed SCP specification will ensure that the requirements of 10 CFR 50.36(c)(1)(ii)(A) are met. RAI 16.2-145 was being tracked as an open item in the SER with open items.

In response, GEH proposed changes to DCD Tier 2, Chapter 7, information regarding the distributed control and information system (DCIS), specifically in DCD Tier 2, Sections 7.1.3.4,

“Q-DCIS Testing and Inspection Requirements,” and 7.1.5.4, “N-DCIS Testing and Inspection Requirements.” These changes included adding references to specific qualified distributed control and instrumentation system (Q-DCIS) hardware platforms (e.g., NUMAC, TRICON); descriptions of DCIS online self-diagnostic features; descriptions of the N-DCIS technical specifications monitor (TSM); and descriptions of Q-DCIS SRs for frequent monitoring for gross channel failure (i.e., channel checks), periodic confirmation of actuation settings (i.e., channel calibrations), and the overall functioning of all the devices in the system (i.e., CFT, LSFT, and response time tests). In response, GEH stated that, “The basic [instrumentation] operability requirements and objectives of the Limiting Safety System Settings (LSSS) are not unique to digital protection systems compared to analog protection systems using bistables.” The staff found that the additional information clarified the overall approach to Q-DCIS testing, but was insufficient to determine the acceptability of using self-diagnostic features to meet SRs because it did not include digital platform-specific operational experience and test data to support using self-diagnostic features to meet SRs.

In response to RAI 16.2-145, GEH also proposed relaxing surveillance frequencies for Q-DCIS instrumentation channel checks to 24 hours and CFTs to 24 months based on the capabilities of the online self-diagnostic features to continually support the objectives of these surveillances. However, the staff determined that it had insufficient design information regarding the online self-diagnostic features to accept the proposed surveillance frequency relaxations based on the use of online self diagnostics to meet channel check and CFT SRs. In RAI 16.2-145 S01, the staff requested that GEH revise these surveillance frequencies to be consistent with the BWR/6 STS.

In response, GEH proposed to revise the surveillance frequencies for channel checks and CFTs for Q-DCIS instrumentation functions to be consistent with the BWR/6 STS. These changes are acceptable because the SR frequencies for channel checks and CFTs are consistent with the STS frequencies for equivalent instrumentation functions. Table 16-7 in this report lists these frequencies for each instrumentation function, which are discussed in Sections 16.2.6.4.1 and 16.2.6.4.2 of this report.

GEH also proposed the following changes:

- Replace specific references to Q-DCIS hardware platforms with “safety-related platforms” in DCD Tier 2, Section 7.1.3.4.
- Revise the description of the scope of a CFT contained in DCD Tier 2, Section 7.1.3.4 and the bases for GTS Section 3.3 to include the “sensor input through the digital trip module (DTM) function,” but not the logic output contact.
- Revise the description of the scope of the LSFT contained in DCD Tier 2, Section 7.1.3.4 and the bases for GTS Section 3.3 to include “all logic components required for operability of a logic circuit, from as close to the sensor as practicable up to, but not including, the actuated device.”
- Replace “instrument” with “logic processor or logic function” to describe self-diagnostics, internal clocks, and cycle in the discussion of response time testing in DCD Tier 2, Section 7.1.3.4.

In summary, logic portions of the Q-DCIS are tested in accordance with SRs for response time tests and LSFTs, which are included in “actuation” specifications. Instrumentation portions

(sensor channels) of the Q-DCIS are tested in accordance with SRs for channel checks, CFTs, and channel calibrations, which are included in “instrumentation” specifications. Response time testing is also specified for sensor channel functions, where appropriate. The staff finds that these changes are acceptable because they are consistent with the definitions of instrumentation surveillances, which are specified in GTS Section 1.1 and the DCIS design, as described in DCD Tier 2, Revision 9, Chapter 7. GEH also proposed other changes to the GTS Section 3.3 SRs as follows:

- Add SR 3.3.1.6.3, channel check of required SRNM channels during operation in Modes 3, 4, and 5 once per 24 hours, to be consistent with the equivalent STS SR 3.3.1.2.3, which also has a 24-hour frequency and applies during operation in equivalent BWR/6 Modes 3 and 4.
- Remove channel check from GTS 3.3.2.1 because the equivalent STS 3.3.2.1 does not specify a channel check for control rod block instrumentation.
- Revise SR 3.3.1.3.1 to require a CFT only for manual scram function channels, with a 7-day frequency, consistent with the equivalent STS SR 3.3.1.1.5.
- Add SR 3.3.1.3.2 to require a CFT for the reactor mode switch - shutdown position function with a frequency of 24 months, consistent with the equivalent STS SR 3.3.1.1.10.
- Add SR 3.3.1.4.4 to require a CFT once every 92 days for NMS instrumentation Functions 2.b, 2.c, 2.d, and 3, consistent with the equivalent STS SR 3.3.1.1.7. Note: The frequency was changed to 31 days in DCD Revision 6 based on the response to RAI 16.2-145 S02.
- Add SR 3.3.1.6.6 to require a CFT once every 31 days for SRNM channels during operation in Modes 3, 4, and 5, consistent with the equivalent STS SR 3.3.1.2.6 which also has a 31-day frequency and applies during operation in the equivalent BWR/6 Modes 3 and 4.

These changes are acceptable because they are consistent with the equivalent STS SRs, as noted.

The staff noted that the discussions in DCD Tier 2, Chapter 7 concerning Q-DCIS testing and the discussions in the GTS Section 3.3 bases regarding CFTs appeared to imply that use of online self-diagnostics of the safety-related platforms would be required in the performance of SRs on Q-DCIS instrumentation. The staff concluded that this is not an issue for the following reasons, based on information included in the DCD:

- Inspection, Test, Analysis, and Acceptance Criterion (ITAAC) Item 13.a in DCD Tier 1, Revision 6, Table 2.2.15-2, addresses IEEE Standard 603, “IEEE Standard Criteria for Safety Systems for Nuclear Power Generating Stations - Description,” Criterion 5.10, “Repair,” and states the following:

The software projects have self-diagnostic features that facilitate the timely recognition, location, replacement, repair, and adjustment of malfunctioning equipment.

The acceptance criterion for this item states the following:

The software project design phase summary baseline review records (BRR) confirm that the software project self-diagnostic functions locate failure to the component level. {{Design Acceptance Criteria}}

The staff notes that completion of ITAAC Item 13.a will involve verification of the implementation of Branch Technical Position 7-17, "Guidance on Self-Test and Surveillance Test Provisions," which will enable the staff to determine the acceptability of using the self-diagnostic feature of the digital instrumentation platforms, which have been chosen by the ESBWR Licensee, as a tool for performing channel checks and CFTs on ESBWR PTS-required instrumentation functions. In order for a COL applicant to revise the FSAR and GTS bases to permit use of self-diagnostic features, it must first obtain NRC approval of an exemption from the ESBWR design certification rule. The staff finds that this change process will ensure that an adequate technical basis is established before self-diagnostic features are allowed to be credited as a tool for performing channel checks and CFTs.

- DCD Tier 2, Chapter 7 and the GTS bases in the ESBWR design certification, and FSAR Chapter 7 and the PTS bases in a plant-specific FSAR for a licensed ESBWR facility will not allow crediting the self-diagnostic feature of the digital instrumentation platforms as a tool for performing channel checks and CFTs on ESBWR GTS-required instrumentation functions, without first departing from the design certification rule or revising the licensing basis as previously described.
- The PTS definitions of channel check and CFT for an ESBWR COL are expected to match the ESBWR GTS definitions, which match the definitions in the BWR/6 STS. These definitions do not describe the tools used to perform these surveillances.

Based on the evaluation of the applicant's response to RAI 16.2-145 S02 in Section 16.2.6.4.2 of this report, as well as the above information, RAI 16.2-145 is resolved.

RAIs 16.2-152, 16.2-153, and 16.2-154 The staff requested GEH to do the following because the GTS bases appeared to lack sufficiently detailed information:

- Add information to GTS bases for instrumentation requirements to identify all devices in the channel required to be tested by a CFT for each GTS instrument function.
- Add information to GTS bases for instrumentation requirements to define logic circuit and identify the logic circuit devices tested by LSFT.
- Identify all ESBWR instrumentation devices in DCD Tier 2 that GTS require to be operable to ensure the LCO-specified safety function can be met.
- Show that ESBWR GTS-required testing and calibration will ensure the necessary quality of instrumentation devices is maintained.

RAIs 16.2-152, 16.2-153, and 16.2-154 were being tracked as open items in the SER with open items.

In response to these RAIs, GEH did not propose adding details to the bases for GTS Section 3.3 to identify all devices in the channel tested by a CFT, all logic circuit devices tested by a LSFT, and all instrumentation devices necessary for the LCO-specified safety function. The requested level of detail is contained in the DCD and its addition to the bases would result

in a greater level of detail than that contained in the bases for STS Section 3.3. GEH also stated that the changes to the information in DCD Tier 2, Chapter 7, regarding the Q-DCIS in DCD Tier 2, Section 7.1.3.4 and associated changes to the bases for GTS Section 3.3, which were made in response to RAI 16.2-145, indicate that testing and calibration, in accordance with the TS, will maintain the necessary quality of instrumentation devices. Based on the resolution of RAI 16.2-145, the staff concurs with these statements and finds the GEH responses to these RAIs acceptable. Therefore, RAIs 16.2-152, 16.2-153, and 16.2-154 are resolved.

RAI 16.2-146 The staff requested that GEH define the terms “nominal trip setpoint,” “allowable value,” “as-found tolerance band,” and “leave alone tolerance band,” which proposed GTS 5.5.11, “Setpoint Control Program (SCP),” requires establishing and documenting using a specified setpoint methodology for TS-required automatic protection instrumentation functions. The staff noted that channel calibration tests for such instrumentation functions must evaluate the channel to verify that it is functioning as required before returning it to service when the as-found channel setting is found to be conservative with respect to the AV, but outside its predefined AFT band. The staff also requested that GEH (1) justify why it chose these setpoint methodology terms for establishing digital protection channel operability during a channel calibration and (2) explain qualitatively what is meant by a leave alone tolerance band for a digital protection channel. The staff requested this information to understand how the proposed SCP will ensure that the requirements of 10 CFR 50.36(c)(1)(ii)(A) are met. RAI 16.2-146 was being tracked as an open item in the SER with open items.

In response, the applicant revised its proposed SCP specification to require documentation of the NTSP_F, AV, AFT, and ALT for each TS-required automatic protection instrumentation function in the GTS and to require that they be calculated in accordance with the NRC-approved setpoint methodology. The staff reviewed the proposed setpoint methodology presented in NEDE-33304P, Revision 4, “GEH ESBWR Setpoint Methodology,” as a part of the ESBWR design certification. Because the staff’s review of the setpoint methodology is being tracked under RAIs 7.1-102 and 7.1-141, and the review of the SCP specification is being tracked under RAI 16.2-156, the staff considers RAI 16.2-146 to be resolved.

RAI 16.2-149 The staff requested that GEH provide an analysis to show that elements of the proposed SCP specification are sufficient to ensure that the requirements of 10 CFR 50.36(c)(3) will be met, including an appropriate basis for the setpoint design basis (setting basis) for each instrumentation function with a specified instrument calibration performed in accordance with the SCP. RAI 16.2-149 was being tracked as an open item in the SER with open items. In response, the applicant revised its proposed SCP specification and setpoint methodology (NEDE-33304P), which it stated contains the requested analysis. The applicant also highlighted ITAAC #10 in DCD Tier 1, Table 2.2.15-2, which requires the performance of inspections, tests, and analyses to verify that the instrumentation settings for safety-related functions are defined, determined, and implemented based on the approved setpoint methodology. As stated in the discussion of RAI 16.2-146, the staff’s review of the setpoint methodology is being tracked under RAIs 7.1-102 and 7.1-141, and the review of the SCP specification is being tracked under RAI 16.2-156. Therefore, RAI 16.2-149 is resolved.

16.2.6.6 Summary Conclusion for Instrumentation Specifications

Section 3.3 of the ESBWR GTS regarding safety-related instrumentation systems implements modified versions of the STS associated with the equivalent safety functions. These specifications conform to the format and usage rules of the STS and are functionally equivalent to those in the STS. As explained previously, the staff finds that the ESBWR design differences

justify GEH's decision not to specify LCOs for the STS instrumentation system functions noted above. The staff considers the ESBWR instrumentation GTS and bases to be acceptable because the specifications will ensure that the designated instrumentation systems are capable of performing their intended safety functions, as assumed in the safety analyses, in the event of a DBA or transient.

16.2.7 ESBWR GTS Section 3.4, "Reactor Coolant System"

The ESBWR RCS specifications correspond to those in the STS, as follows:

<u>STS</u>	<u>ESBWR TS</u>	<u>ESBWR TS TITLE (*STS TITLE)</u>
3.4.1*	None	(*Recirculation Loops Operating)
3.4.2*	None	(*Flow Control Valves)
3.4.3*	None	(*Jet Pumps)
3.4.4*	3.4.1	Safety Relief Valves (*Safety/Relief Valves)
3.4.5*	3.4.2	RCS Operational Leakage (*same)
3.4.6*	None	(*RCS Pressure Isolation Valve Leakage)
3.4.7*	3.3.4.1	RCS Leakage Detection Instrumentation (*same)
3.4.8*	3.4.3	RCS Specific Activity (*same)
3.4.9*	None	(*Residual Heat Removal Shutdown Cooling System - Hot Shutdown)
3.4.10*	None	(*Residual Heat Removal Shutdown Cooling System - Cold Shutdown)
3.4.11*	3.4.4	RCS Pressure and Temperature (P/T) Limits (*same)
3.4.12	3.4.5	Reactor Steam Dome Pressure (*same)

Section 3.4 in the ESBWR GTS is similar to the corresponding STS for the RCS for SRVs, RCS operational leakage, RCS leakage detection instrumentation, RCS specific activity, RCS pressure and temperature (P/T) limits, and reactor steam dome pressure. The ESBWR design does not include certain systems associated with previous BWRs, and the following paragraphs discuss these deviations and exclusions from the STS.

The ESBWR design has no recirculation loops with recirculation pumps, flow control valves, or jet pumps; hence, the GTS contain no LCOs for these BWR/6 systems.

The ESBWR GTS do not include an LCO corresponding to STS 3.4.6 for RCS pressure isolation valve (PIV) leakage. RCS PIVs are defined as any two normally closed valves in series within the RCPB. The function of RCS PIVs is to separate the high-pressure RCS from an attached low-pressure system to protect the RCS pressure boundary. As discussed in DCD Tier 2, Chapter 3, Appendix 3K, "Resolution of Intersystem Loss of Coolant Accident," the periodic surveillance and leak rate testing requirements for high-pressure to low-pressure isolation valves is not applicable to the ESBWR because the design does not contain a PIV between the RCPB and a low-pressure piping system.

The ESBWR GTS do not contain an LCO for the dual purpose RWCU/SDC system. This system most resembles the BWR/6 residual heat removal shutdown cooling system but is not designated as safety related and satisfies none of the four criteria of 10 CFR 50.36(c)(2)(ii). The combination of the ICS, the GDCS, and the passive containment cooling system (PCCS) performs the safety-related DHR functions in the ESBWR design.

RAI 16.2-119 The staff asked the applicant to provide an analysis that explicitly assumes that just one SRV functions in order for the GTS LCO 3.4.1 to require just two SRVs to be operable. In response the applicant clarified DCD Tier 2, Subsections 5.2.2.3.2 and 5.2.2.3.3, but made no change to LCO 3.4.1. In RAI 16.2-119 S01, the staff quoted the following statement from the applicant's response to RAI 21.6-91:

Changes to DCD Tier 2, Figure 5.2-4 will be made in response to this RAI [21.6-91]. Figure 5.2-4 will be updated based on the result of a TRACG analysis that uses the following input files: MSIVF_EOC_NOFW.INP and SCRAM_PRESS_8GROUPS.TDT.

The staff then stated that, since the applicant proposes in GTS LCO 3.4.1 to rely on only one SRV for overpressure protection, it should verify that the input files used to generate DCD Tier 2, Figure 5.2-4 credit only one SRV. In addition, the staff asked the applicant to correct the apparent discrepancy between the last sentence of the first paragraph of DCD Tier 2, Section 5.2.2.3.3, where it states that the [full open] flow through three SRVs (not one) is needed to mitigate the MSIV closure with high neutron flux scram event. RAI 16.2-119 was being tracked as an open item in the SER with open items.

In response to RAI 16.2-119 S01, GEH stated the following:

The TRACG analysis that credits the capacity of only 1 SRV for over pressure protection has been performed with the input file MSIVF_EOC_NOFW.INP and kinetics file SCRAM_PRESS_8GROUPS.TDT. The input file was modified to simulate the SRV capacity change from approximately 3 SRVs to that of 1 SRV. A replacement for Figure 5.2-4 has been generated for inclusion in the DCD, but has been changed to Figure 15.5-11 as the analysis for the MSIV closure with flux scram event is now described in Section 15.5.1.1 of the DCD. The analysis resulted in no change in the maximum reactor vessel pressure and demonstrates that 1 SRV is sufficient to mitigate the reactor vessel pressure response.

The staff verified that DCD Tier 2, Revision 6, incorporated the described changes to the Chapter 15 analyses. Based on the applicant's response and changes to the DCD, RAI 16.2-119 is resolved.

RAI 16.2-2 The staff requested that the applicant provide a technical justification for relaxing the 8-hour frequency of STS SR 3.4.2.1, which calls for verifying RCS unidentified and total leakage, to a 12-hour frequency in GTS SR 3.4.2.1. In response, the applicant referenced the guidance provided in GL 88-01, Supplement 1, which states that monitoring RCS leakage every 4 hours creates an unnecessary administrative hardship for plant operators. The proposed 12-hour frequency of ESBWR SR 3.4.2.1 is acceptable based on guidance in GL 88-01, Supplement 1, which allows RCS leakage measurements to be taken once per shift, not to exceed 12 hours. Therefore, RAI 16.2-2 is resolved.

RAI 16.2-121 The staff noted that ESBWR GTS 3.4.3 for RCS specific activity conforms to STS 3.4.8, except that it does not specify an option for placing the plant in hot shutdown within 12 hours and cold shutdown (or stable shutdown) within 36 hours in lieu of isolating all main steam lines (MSLs) within 12 hours. Failure to include this option in ESBWR GTS 3.4.3 reduces the operational flexibility for removing decay heat under conditions requiring MSLI with a substantial previous power history. The bases for the equivalent STS 3.4.8 allow the option of placing the plant in Mode 3 within 12 hours and Mode 4 within 36 hours for those instances in

which MSLI is not desired (e.g., because of the decay heat loads). In STS Mode 4, cold shutdown, the requirements of the LCO are no longer applicable. ESBWR GTS 3.4.3 should include the option of being in Mode 3 within 12 hours and in Mode 5 within 36 hours. If the option will not be used, the staff asked the applicant to discuss the anticipated DHR methodology (i.e., ICS, FAPCS) in the event the MSLs are isolated and a substantial previous power history exists. The staff presented this issue to the applicant in RAI 16.2-121. In response, the applicant committed to revise GTS 3.4.3, Action B, to include the option of placing the unit in Mode 5. In DCD Revision 4, shutdown actions were added to Action B of GTS 3.4.3 as an option to isolating all MSLs. Therefore, RAI 16.2-121 is resolved. However, in DCD Revision 5, GEH revised (1) the applicability of GTS 3.4.3 by removing the condition "with any main steam line not isolated" and (2) Action B of GTS 3.4.3 by removing the action to "isolate all main steam lines," leaving only the actions to be in Mode 3 within 12 hours and Mode 5 within 36 hours, while determining the dose equivalent I-131 once every 4 hours. In the table entitled, "Chapter 16 Changes from Revision 4 to Revision 5," which GEH submitted with DCD Revision 5, the applicant stated in Items 210 and 211 that these changes were made for "consistency with DCD dose consequences results." With these changes, GTS 3.4.3 will be applicable in Modes 1, 2, 3, and 4, regardless of the isolation state of any MSL, and will require a unit shutdown to Mode 5 in the event dose equivalent I-131 is not restored to within 7400 becquerels per gram (Bq/gm) (0.2 microCuries per gram [$\mu\text{Ci/gm}$]) within the specified Completion Time of 48 hours or exceeds 148,000 Bq/gm (4.0 $\mu\text{Ci/gm}$). Since these provisions are more restrictive on unit operation, the staff finds them acceptable.

ESBWR GTS 3.4.4, for the RCS P/T limits, in conjunction with GTS 5.6.4, "RCS Pressure and Temperature Limits Report (PTLR)," conforms to STS 3.4.11 and STS 5.6.6, except that the SRs associated with recirculation pumps are omitted since these pumps are not in the ESBWR design. The P/T limits are not derived from DBA analyses, but are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB. In operating BWR designs, the determination that reactor recirculation loop and vessel component differential temperatures are within the applicable pressure and temperature limits report (PTLR) limits before changing reactor recirculation flow ensures that thermal stresses will not exceed design allowances. The ESBWR design is similar to that of the operating BWRs, except that the design does not include recirculation pumps and associated piping. Reactor coolant circulation through the ESBWR core is accomplished by means of natural circulation, and flow is dependent on the difference in water density between the downcomer region and the core region. Therefore, the ESBWR GTS 3.4.4 does not require surveillances associated with starting recirculation pumps or unisolating reactor recirculation loops and is acceptable.

ESBWR GTS 3.4.5, for reactor steam dome pressure, conforms to STS 3.4.12 and is therefore acceptable.

The ESBWR GTS for the RCS implement modified versions of the STS for the RCS. The staff finds that these specifications are essentially equivalent to those in the STS for the applicable RCS functions. For cases in which the applicant has not included GTS requirements equivalent to STS requirements, ESBWR design differences provide sufficient justification for such omissions. Therefore, based on the resolution of the RCS-related RAIs and the preceding evaluations, the GTS and bases for the RCS are acceptable.

16.2.8 ESBWR GTS Section 3.5, “Emergency Core Cooling Systems (ECCSs)”

The ESBWR uses a passive ECCS rather than the pump-driven, active ECCS of currently operating plants, which is the basis for the STS ECCS requirements. The safety-related ECCS is designed to perform emergency core cooling and DHR, reactor coolant emergency makeup, and safety injection. The ECCS consists of the ADS, the GDCS, and the ICS. The GTS for the ESBWR ECCS generally correspond to the STS for the ECCS, as follows:

<u>STS</u>	<u>ESBWR TS</u>	<u>ESBWR TS TITLE (*STS TITLE)</u>
3.5.1*	3.5.1	ADS (*ECCS - Operating)
3.5.1*	3.5.2	GDCS - Operating (*ECCS - Operating)
3.5.2*	3.5.3	GDCS - Shutdown (*ECCS - Shutdown)
3.5.1*	3.5.4	ICS - Operating (*ECCS - Operating)
3.5.2*	3.5.5	ICS - Shutdown (*ECCS - Shutdown)
3.5.3*	None	(*Reactor Core Isolation Cooling (RCIC) System)

The ESBWR design does not include an active system corresponding to the reactor core isolation cooling system. The ESBWR design does not include a safety-related high-pressure ECCS. Instead, the design provides redundant systems and makeup water supplies to depressurize and reflood the reactor vessel following a LOCA. The ICS is designed to passively remove decay heat with the RCS pressurized.

A combination of the GDCS, the ADS, the SLC system, and the ICS provides the ECCS function. The ECCS is designed to flood the core and provide core cooling following a LOCA. By providing core cooling following a LOCA, the ECCS, in conjunction with the containment, limits the release of radioactive materials to the environment. The functional requirements (e.g., coolant delivery rates) are such that the system performance under all LOCA conditions postulated in the design satisfies the requirements of 10 CFR 50.46. The ECCS is designed to provide protection for any primary system line break up to and including the double-ended break of the largest line; require no operator action until 72 hours after an accident; and ensure a sufficient water source, including the necessary piping and other hardware, such that the containment and reactor core can be flooded for core DHR following a LOCA.

Automatic Depressurization System

The ADS provides reactor depressurization capability in the event of a pipe break. The depressurization function is accomplished through the use of SRVs and DPVs. The ADS is an integral part of the ECCS because GDCS flow to the RPV requires the RPV to be close to containment pressure. The ADS is designed to depressurize the RPV following indication of a LOCA. The ADS consists of eight squib-actuated DPVs and ten SRVs that are configured to function as ADS valves (relief mode) in addition to functioning as spring-loaded safety valves (safety mode) to satisfy LCO 3.4.1. The ten dual-function SRVs are pneumatically actuated when functioning as ADS valves using energy stored in nitrogen accumulators. (Note: The eight SVs are not required to be operable by any LCO.)

Gravity-Driven Cooling System

The GDCS provides flow to the annulus region of the reactor through dedicated nozzles. It provides gravity-driven flow from three separate water pools located within the drywell at an

elevation above the active core region. It also provides water flow from the suppression pool to meet long-term, post-LOCA core cooling requirements. The system provides these flows by gravity forces alone (without reliance on active pumps) once the reactor pressure is reduced to near containment drywell pressure.

The three subsystems of the GDCS are the GDCS short-term cooling (injection subsystem); the GDCS long-term cooling (equalizing subsystem); and the GDCS deluge subsystem. Three GDCS pools, located above the wetwell at an elevation above the reactor core, contain the water that supports all four GDCS trains for the injection, equalizing, and deluge subsystems. The GDCS injection subsystem is capable of refilling the RPV following a LOCA after the RPV is depressurized by the ADS. The GDCS equalizing subsystem provides long-term, post-LOCA water makeup by connecting the annulus region of the reactor to the suppression pool. The GDCS deluge subsystem is used to dump water from the GDCS pools to the lower drywell in the event of a severe accident. The ACM in DCD Tier 2, Section 19A, addresses the availability requirements for the GDCS deluge subsystem, which is not included in the GDCS LCO. Section 22.5 of this report evaluates the RTNSS controls of the ACM.

GDCS injection and equalizing subsystems are required to be operable in Modes 1, 2, 3, and 4 when there is considerable energy in the reactor core and core cooling may be required to prevent fuel damage following a LOCA. GDCS operability requires eight branch lines of the injection subsystem (i.e., all four injection trains) and four trains of the equalizing subsystem. Operability of the squib-actuated GDCS valves requires electrical continuity of redundant explosive charge firing circuits to each valve. However, one squib charge firing circuit may be bypassed intermittently for required testing or maintenance. Operability of each GDCS branch line requires that the water level in the associated GDCS pool be within specified limits. All GDCS RPV block valves, GDCS pool block valves, and suppression pool block valves must be locked open.

Two injection subsystem branch lines associated with each GDCS pool and two GDCS equalizing subsystem trains are required to be operable in Modes 5 and 6, except with the buffer pool gate removed and water level ≥ 7.01 m (23.0 ft) over the top of the reactor pressure vessel flange, to provide additional water inventory inside the containment to respond to a loss of nonsafety-related DHR capability or a loss of reactor coolant inventory. Loss of DHR capability could result from a loss of RWCU/SDC, a loss of reactor component cooling water, a loss of plant service water, or a loss of preferred power. Loss of reactor coolant inventory could result from pipe breaks in the RCS associated with maintenance or refueling, misalignment of systems connected to the RCS, or leakage during replacement of CRD assemblies.

Isolation Condenser System

The ICS provides additional liquid inventory upon opening of the condensate return valves and initiating system operation. The ICS actuates automatically following RPV isolation and transfers sufficient heat from the RPV to the IC/PCCS pool to prevent SRV actuation. The ICS is designed to remove sufficient decay heat following RPV isolation to cool the reactor to safe-shutdown conditions within 36 hours and maintain the reactor in a safe condition for an additional 36 hours with minimal loss of RCS inventory. The ICS also provides water inventory to the RPV at the start of a LOCA and provides the initial RPV depressurization following a loss of feedwater, which allows ADS initiation to be delayed. The ICS is also assumed available to respond to a station blackout (SBO) and an anticipated transient without scram (ATWS).

The ICS consists of four independent trains. Each ICS train includes a heat exchanger (i.e., an isolation condenser [IC]), a steam supply line that connects the top of the IC to the RPV, a condensate return line that connects the bottom of the IC to the RPV, a high-point purge line, and vent lines from both the upper and lower headers of the IC. The ICs are located above the containment and are submerged in a large pool of water (the IC/PCCS pool) that is at atmospheric pressure. Steam produced in IC/PCCS pools by boiling around an IC is vented to the atmosphere.

The two IC/PCCS inner expansion pools, the equipment pool, and the reactor well pool supply makeup water. The equipment pool and reactor well pool are normally isolated from the inner expansion pools because the equipment pool and reactor well are maintained at a higher water level than the inner expansion pools. The equipment pool is connected to each inner expansion pool by redundant flow paths - one containing a squib valve and one containing a pneumatic valve - that open automatically when there is a low level in either inner expansion pool. The equipment pool is connected to the reactor well pool through the reactor well gate, which is not installed during normal plant operation. By connecting the equipment pool and reactor well pool to the inner expansion pools, the volume of water available to the ICS and PCCS subcompartments is sufficient to support DHR for 72 hours without operator action or the need to replenish the water in the inner expansion pools.

Four ICS trains are required to be operable in Modes 1 and 2 and in Modes 3 and 4 when less than 2 hours have passed since the reactor was critical to remove reactor decay heat or provide additional RCS inventory following a LOCA, a loss of feedwater, or a reactor shutdown with isolation. In addition, in Modes 1 and 2, the ICS is required to be operable to prevent unnecessary automatic reactor depressurization or SRV actuation following RPV isolation or low RPV water level events. Operation of three of the four ICS trains will limit RCS pressure enough to prevent SRV actuation. By conserving reactor water inventory following the RPV isolation, the ICS minimizes the need for automatic reactor depressurization that would be required to gain additional water inventory from low-pressure sources.

Two ICS trains are required to be operable to provide an automatic backup DHR method in Modes 3 and 4, when more than 2 hours have elapsed since the reactor was critical, and in Mode 5. Although various methods of active DHR using feed and bleed may be available, operability of two ICS trains is intended to ensure the availability of at least one highly reliable and passive automatic alternative to the RWCU/SDC system for DHR. If the normal method of DHR is lost when in Mode 5, the two required ICS trains will automatically remove decay heat following RCS heatup and pressurization.

RAIs 16.2-32, 16.2-98, 16.2-107, and 16.2-108 In RAI 16.2-32, the staff requested that the applicant provide action requirements addressing the combinations of inoperable ADS, SRV, DPV, and GDCS, or justify not addressing these combinations. RAI 16.2-32 was being tracked as an open item in the SER with open items. In response, the applicant proposed to enclose the conditions, required actions, and completion times for LCOs 3.5.1 and 3.5.2 in brackets, indicating that additional analysis or justification is required before approval, until the DCD changes that provide the required justification are approved. The applicant subsequently removed the brackets from LCOs 3.5.1 and 3.5.2, Actions A through E, and proposed to base the ECCS required actions and completion times on a pending ECCS N-2 topical report, which the bases for GTS 3.5.1 and 3.5.2 would reference. In RAI 16.2-108, the staff requested that GEH submit the ECCS N-2 topical report. In RAI 16.2-98, the staff also asked GEH to clarify the bases for the actions of GTS 3.5.2. RAI 16.2-98 was being tracked as an open item in the

SER with open items. In response to RAI 16.2-98, GEH stated that it would bracket the actions of GTS 3.5.2 until supporting analysis is completed.

Because the scope of RAI 16.2-32 includes a request to clarify the bases for GTS 3.5.2, resolution of RAI 16.2-32 also resolves RAI 16.2-98. In RAI 16.2-107, the staff asked the applicant to explain why the action requirements of GTS 3.5.1 in DCD Revision 1 did not require reducing reactor steam dome pressure when two or more ADS SRVs or two or more DPVs are inoperable. Subsequent changes to the action requirements of GTS 3.5.1, as described in the resolution of RAIs 16.0-7, 16.2-32, and 16.2-98, removed the basis for this request and removed any reference to an ECCS N-2 topical report, as well. With these changes, RAIs 16.2-107 and 16.2-108 are resolved.

In a supplemental response to RAI 16.2-32, the applicant proposed new action requirements, without brackets, for ADS, GDCS - Operating, and ICS - Operating and incorporated these changes into DCD Revision 5. GEH stated the following in its response:

In DCD Revision 5, GEH is revising LCO 3.5.1, LCO 3.5.2, and LCO 3.5.4 and the supporting Bases to Required Actions based on the existing analyses described in DCD, Tier 2, Revision 4, Table 6.3-6, "Single Failure Evaluation." This change establishes Actions and Completion Times (CTs) that require the plant be placed outside the Applicability when more than one ADS valve, more than one GDCS injection branch line, more than one GDCS equalizing train, or more than one ICS train is inoperable. Additionally, LCO 3.5.1, LCO 3.5.2, and LCO 3.5.4 are revised to require the operability of ECCS actuation by the Diverse Protection System (DPS) and add Actions when a DPS actuator is not operable. [Note; DPS actuator operability to satisfy LCO 3.5.4 for ICS was subsequently removed, as described below in the discussion of RAI 16.2-174.] Finally, the SRs for periodic verification of squib continuity were expanded to include both squib actuators and solenoid actuators and include verification that the actuators are associated with electrical divisions that are required to be operable by LCO 3.8.6, "Distribution Systems - Operating," to assure continuity with the corresponding instrumentation support systems.

In conjunction with these changes, GEH is revising the Bases to clarify requirements for the actuators (i.e., squib initiators and solenoid valves) needed to support ECCS valve operability. Each ECCS valve has four actuators - three that are initiated by Safety System Logic and Control/Engineered Safety Features (SSLC/ESF) instrumentation and one that is initiated by the DPS. Any one of the four actuators is capable of actuating the ECCS valve. Because only three of the four safety-related electrical and instrumentation actuation divisions are required to be operable, two of the three SSLC/ESF actuators are required for ECCS valve operability. Two SSLC/ESF actuators are necessary to ensure the minimum requirements for ECCS specified in Table 6.3-6 are met if a single failure occurs in one of the three required electrical or instrumentation actuation divisions. Because all ECCS valves will still actuate when a required electrical or instrumentation division fails, minimum ECCS requirements are met even when an individual ECCS valve fails concurrently with the failure of a required electrical or instrumentation actuation division. A 14 day Completion Time for restoration of an inoperable ADS valve, GDCS injection line, GDCS equalizing train, or ICS train is proposed based on engineering judgment considering the low probability

of the failure of a required electrical or instrumentation actuation division concurrent with a design basis event during this period.

The staff finds the above described changes to the required actions (and bases) for restoration of an inoperable ADS valve, GDCS injection line, GDCS equalizing train, or ICS train to operable status acceptable for the reasons stated in the applicant's response, and because each of these conditions corresponds to or is bounded by the worst single failure following a LOCA as shown in DCD Tier 2, Revision 9, Table 6.3-6. In these conditions, minimum ECCS requirements are still satisfied even with the additional failure of a required electrical division or instrumentation actuation division. The staff finds this capability to be a sufficient basis to accept the 14-day completion time to restore an inoperable ADS valve, GDCS injection line, GDCS equalizing train, or ICS train to operable status during unit operation in Modes 1, 2, 3, and 4.

The staff finds the proposed actions, related to loss of common-mode failure protection, for the four conditions of one ADS valve with DPS initiator inoperable, two or more ADS valves with DPS initiator inoperable, one or more GDCS subsystems with one DPS initiator inoperable, and one or more GDCS subsystems with two or more DPS initiators inoperable, are acceptable for the reasons described below in the discussion of RAI 16.2-174.

In the conditions of two or more ADS valves inoperable, two or more branch lines of the GDCS injection subsystems inoperable, and two or more GDCS equalizing trains inoperable, for reasons other than inoperable DPS initiators, the minimum ECCS requirements may not be satisfied. The staff finds the proposed actions for these conditions in LCOs 3.5.1 and 3.5.2 acceptable because they require placing the unit outside the applicability of the associated LCO in a time period consistent with the capability of the unit to be placed in Mode 5 using normal shutdown procedures and without challenging safety systems.

The staff also finds the above described changes to the SRs acceptable because the proposed SRs will assure that the necessary quality of all ADS, GDCS, and ICS components is maintained, and that the associated LCOs will be met. The staff also finds the squib-valve SRs acceptable as described below in the discussions of RAI 16.2-35 and RAI 16.2-173.

However, the response failed to justify the applicant's decision not to include a condition for an inoperable injection branch line concurrent with an inoperable equalizing train in the action requirements of GTS 3.5.2 and 3.5.3. In RAI 16.2-32 S01, the staff asked the applicant to propose this condition and restoration actions with a 24-hour completion time, with accompanying changes to the bases. Since this issue was common to both RAIs 16.2-98 and 16.2-32, RAI 16.2-98 is considered resolved. In response, GEH explained that the function of the GDCS injection branch lines and the function of the GDCS equalizing trains are not impacted by degradation in the other subsystem. Since the injection and equalizing subsystem functions are designed to meet short term and long term emergency cooling needs, respectively, the staff finds that the applicant's response is accurate. Based on this, the staff concludes that no additional action requirement to address the condition of one branch line and one equalizing train concurrently inoperable is warranted. Therefore, RAI 16.2-32 is resolved.

However, in response to RAI 16.2-32, GEH also proposed additional action requirements to address the condition of one or more ADS, GDCS, or ICS valves with DPS actuator inoperable during unit operation in Modes 1, 2, 3, and 4. The staff requested that the applicant address these additional action requirements in RAI 16.2-174.

GTS 3.5.3, “GDCS - Shutdown,” is applicable during Mode 5, and during Mode 6 except with the buffer pool gate removed and water level greater than or equal to 7.01 m (23.0 ft) over the top of the reactor pressure vessel flange. The staff finds the proposed action requirements acceptable as described in the following:

- Action A: Similar to GTS 3.5.1 and 3.5.2, a completion time of 14 days is specified (Action A) for restoring one of the six required GDCS injection branch lines, one of the two required GDCS equalizing trains, or one required ADS valve to operable status. The staff finds this completion time acceptable because the remaining operable required branch lines, required equalizing train, and required ADS valves provide sufficient RPV flooding capability to recover from a loss of decay heat removal capability, LOCA, or inadvertent vessel draindown. The 14-day completion time is also acceptable because of the low probability of an event requiring GDCS injection occurring concurrent with another failure of a GDCS branch line or equalizing train, or an ADS valve while in this condition during this time.
- Action B: In the condition of two or more of the six required branch lines inoperable, the volume from one, two, or three of the GDCS pools may be unavailable for event mitigation. Required Action B.1 proposes to permit operation for up to the 14-day completion time of Action A (plus 24 hours as permitted under the conditions described in GTS Section 1.3), provided that within 4 hours the unit ensures the capability of two methods of injecting a combined water volume equivalent to the required GDCS pool volume. The DCD shows that possible available methods include RPV injection using the CRD system from the condensate storage tank, and the FAPCS system from the suppression pool. In Modes 5 and 6 both trains of the FAPCS system are required to be available by the ACM for the suppression pool cooling, alternate shutdown cooling, and low pressure coolant injection functions; each train has a separate ACM-required standby diesel generator ac power source. The 4-hour completion time is acceptable because it provides sufficient time to verify the capability of the two alternate methods of RPV makeup, and because of the low probability of an event requiring GDCS injection occurring while in this condition during this time.
- Action C: In the condition of both required branch equalizing subsystem trains inoperable, the volume from one, two, or three of the GDCS pools may be unavailable for event mitigation. Required Action C.1 proposes to permit operation for up to the 14-day completion time of Action A (plus 24 hours as permitted under the conditions described in GTS Section 1.3), provided that within 4 hours the unit ensures the capability of two methods of injecting a combined water volume equivalent to the required suppression pool volume. The DCD shows that possible available methods include RPV injection using the CRD system from the condensate storage tank, and the FAPCS system from the suppression pool. In Modes 5 and 6 both trains of the FAPCS system are required to be available by the ACM for the suppression pool cooling, alternate shutdown cooling and low pressure coolant injection functions; each train has a separate ACM-required standby diesel generator ac power source. The 4-hour completion time is acceptable because it provides sufficient time to verify the capability of the two alternate methods of RPV makeup, and because of the low probability of an event requiring GDCS injection occurring while in this condition during this time.
- Action D: In the condition of GDCS inoperable due to two or more required ADS valves inoperable, RPV venting capacity may not be sufficient to allow GDCS injection. Required Action D.2 proposes to permit operation in this condition for up to 72 hours, provided that within 4 hours RCS vent path(s) with relief capacity equivalent to the required number of

ADS valves (equivalent to six DPVs) is established, which would restore capability for GDCS injection (Required Action D.1.1). Alternately, Required Action D.2 proposes to permit operation in this condition for up to 72 hours, provided that within 4 hours the unit ensures the capability of two methods of injecting a combined water volume greater than or equal to the required GDCS and suppression pool volumes (Required Action D.1.2). The DCD shows that possible available methods include RPV injection using the CRD system from the condensate storage tank, and the FAPCS system from the suppression pool. In Modes 5 and 6 both trains of the FAPCS system are required to be available by the ACM for the suppression pool cooling, alternate shutdown cooling and low pressure coolant injection functions; each train has a separate ACM-required standby diesel generator ac power source. The 4-hour completion time is acceptable because it provides sufficient time to either restore required RPV vent capacity or verify the capability of two alternate methods of RPV makeup, and because the probability of an event occurring in this condition during this time is low. The 72-hour completion time to restore the GDCS to operable status as required by LCO 3.5.3 (by restoring the required number of ADS valves to operable status) is acceptable because of the compensatory measures to either restore the GDCS injection functional capability or establish two alternate methods of RPV makeup, and because of the low probability of an event requiring GDCS injection occurring while in this condition during this time.

- Action E: In the condition of GDCS inoperable “for reasons other than Condition A, B, or C,” other reasons include insufficient water volume in one or more GDCS pools or in the suppression pool. The condition is written to capture any instances of failure to meet LCO 3.5.3 that are not addressed by Conditions A, B, and C that renders either or both of the GDCS injection and equalizing subsystems inoperable. Required Action E.2 proposes to permit operation in this condition for up to 72 hours, provided that within 4 hours the unit ensures the capability of two methods of injecting a combined water volume greater than or equal to the required GDCS and suppression pool volumes (Required Action E.1). The DCD shows that possible available methods include RPV injection using the CRD system from the condensate storage tank, and the FAPCS system from the suppression pool. In Modes 5 and 6 both trains of the FAPCS system are required to be available by the ACM for the suppression pool cooling, alternate shutdown cooling, and low pressure coolant injection functions; each train has a separate ACM-required standby diesel generator ac power source. The 4-hour completion time is acceptable because it provides sufficient time to verify the capability of two alternate methods of RPV makeup, and because the probability of an event occurring in this condition during this time is low. The 72-hour completion time to restore the GDCS to operable status as required by LCO 3.5.3 is acceptable because of the compensatory measure to establish two alternate methods of RPV makeup, and because of the low probability of an event requiring GDCS injection occurring while in this condition during this time.
- Action F: Failure to successfully accomplish any of the required actions of Conditions A, B, C, D, or E before expiration of the associated completion time is a condition in which the water inventory available for RPV injection may not be sufficient to successfully respond to a loss of decay heat removal capability, LOCA, or inadvertent vessel draindown. Required Action F.1, to immediately initiate action to suspend operations with a potential for draining the reactor vessel, is an appropriate action because it minimizes the chance of a vessel drain down event. Required Actions F.2.1 and F.2.2 are also appropriate compensatory measures because they require immediately initiating action to ensure that the reactor building REPAVS and CONAVS area isolation boundaries are, or will automatically be, established in the event of a loss of decay heat removal capability, LOCA, or inadvertent

vessel draindown without sufficient vessel makeup capability. Isolation of REPAVS and CONAVS area boundaries will mitigate the potential radiological consequences of these events. Because these actions are appropriate for the reasons stated, the staff finds them acceptable.

Based on the above evaluation, the staff finds that the action requirements of GTS 3.5.3 are acceptable. The staff finds that the applicability of GTS 3.5.3 is also acceptable because with the buffer pool gate removed and water level greater than or equal to 7.01 m (23.0 ft) over the top of the reactor pressure vessel flange, there is adequate coolant inventory and sufficient heat removal capability for the irradiated fuel in the core in response to a loss of decay heat removal capability, a LOCA, or an inadvertent draindown of the RPV. The adequacy of the water inventory in this condition was addressed by GEH in its response to RAI 16.2-73, which is described below.

RAI 16.2-174 The staff noted that, in DCD Revision 5, GEH proposed action requirements that would allow operation with all ADS, GDCS, and ICS valve DPS actuators inoperable for an entire operating cycle, which would be inconsistent with the actions of GTS 3.3.8.1, which specify a 30-day completion time to restore a DPS instrumentation function to operable status. An inoperable DPS instrumentation function would affect all automatic valves associated with that function, which could include ADS valves, GDCS valves, IC valves, containment isolation valves, and IC/PCCS expansion pool-to-equipment pool cross-connect valves that have TS-required DPS actuators. In response, GEH proposed action requirements to permit just one valve (per subsystem for GDCS - one of eight valves in the injection subsystem, one of four valves in the equalizing subsystem) in each of these systems, except for the ICS, to have an inoperable DPS actuator until the end of the operating cycle. Two or more valves with the DPS actuator inoperable in each of these systems (per subsystem for GDCS) would require restoring all DPS actuators to operable status within 30 days. In response, GEH stated the following:

Operation in the [conditions, as described below, that require restoring the DPS actuator(s) to operable status with a] Completion Time of “prior to entering MODE 2 or 4 from MODE 5” is acceptable because, with the restrictions being added as described below, sufficient DPS actuators remain OPERABLE to mitigate the possibility of digital protection system common mode failures. As such, the remaining DPS actuators will actuate the safety-related functions required to respond to the design basis LOCA concurrent with any additional single failure, including digital protection system common mode failures.

- For ADS, the Specification and associated Bases for TS 3.5.1, Action A, will be revised to limit the number of inoperable DPS actuators to only one ADS valve with the Completion Time of “prior to entering MODE 2 or 4 from MODE 5.” Operation in Action A with one DPS actuator inoperable continues to provide the minimum number of DPS actuated ADS valves that are required to mitigate analyzed accidents concurrent with digital protection system common mode failures. A new Action B and associated Bases will be added to address two or more ADS valves with the DPS actuator inoperable. The new Action B will provide a Completion Time of 30 days, consistent with TS 3.3.8.1 for inoperability of the DPS ADS actuation function.
- For GDCS, the Specification and associated Bases for TS 3.5.2, Action A, will be revised to limit the number of inoperable DPS actuators to only one valve per GDCS subsystem (injection and/or equalizing subsystem) with the

Completion Time of “prior to entering MODE 2 or 4 from MODE 5.” Operation in Action A, with one DPS actuator inoperable on one or both GDSCS subsystems, continues to provide the necessary DPS actuated GDSCS valves to mitigate analyzed accidents with the possibility of digital protection system common mode failures. A new Action B and associated Bases will be added to address two or more valves per GDSCS subsystem with the DPS actuator inoperable. The new Action B will provide a Completion Time of 30 days, consistent with TS 3.3.8.1 for inoperability of the DPS GDSCS actuation function.

- For reactor water cleanup/shutdown cooling system (RWCU/SDC) containment isolation valves (CIVs), the Specification and associated Bases for TS 3.6.1.3 Action A will be revised to limit the Completion Time to 30 days. Because the ESBWR design for RWCU/SDC isolation from DPS is currently not sufficiently detailed defining whether one or both RWCU/SDC CIVs will be equipped with DPS actuators, Action A and associated Bases will be revised to conservatively provide a Completion Time of 30 days [for the condition of one or more RWCU/SDC penetration flow path CIV DPS actuator(s) inoperable], consistent with TS 3.3.8.1 for inoperability of the DPS RWCU/SDC actuation function.
- For the isolation condenser/passive containment cooling system (IC/PCCS) expansion pool-to-equipment pool cross-connect valves, the Specification and associated Bases for GTS 3.7.1 Action A will be revised to address only one inoperable IC/PCCS DPS actuator in the expansion pool-to-equipment pool cross-connect valves between one or both expansion pools and the equipment pool. Operation in Action A continues to provide one operable DPS actuator in at least one connection line for each expansion pool to mitigate the possibility of digital protection system common mode failures. A new Action B will be added to address one or both IC/PCCS expansion pools with both expansion pool-to-equipment pool cross-connect valve DPS actuators inoperable. The new Action B will be provided a Completion Time of 30 days, consistent with GTS 3.3.8.1 for inoperability of the DPS IC/PCCS expansion pool-to-equipment pool cross-connect actuation function.

The DPS actuators for the isolation condenser system (ICS) did not meet criteria for high regulatory oversight. The basis for this is found in DCD Sections 19A.8.1 and 19A.8.4, which describe the results of the regulatory oversight evaluation for DPS. While DPS actuators were not included in Revision 5 of GTS 3.5.4, they are included in Revision 5 of DCD Section 19ACM, “Availability Controls Manual,” specifically in Availability Control (AC) 3.3.[4], “Diverse Protection System (DPS).”

The staff finds the proposed actions to address valves with inoperable DPS actuators acceptable for the reasons stated in the applicant’s response, quoted above. Therefore, RAI 16.2-174 is resolved.

RAI 16.2-34 Based on DCD Revision 1, the staff requested that the applicant provide additional justification for allowing operation to continue for 14 days with just three operable non-ADS SRVs (safety mode), as proposed in GTS 3.4.1, and eight operable ADS-SRVs and six

operable DPVs, as proposed in GTS 3.5.1. In response, the applicant described the three functions performed by the ESBWR SRVs as follows:

- Overpressure protection (addressed in LCO 3.4.1).
- ATWS overpressure protection (addressed by plant configuration management and corrective action programs; not in TS).
- Automatic depressurization of the RPV to support ECCS (addressed by LCO 3.5.1).

As described in DCD Tier 2, Revision 9, Section 5.2.2 and the bases for LCOs 3.4.1 and 3.5.1, the ten ADS-SRVs are equipped with auxiliary actuating devices allowing them to function as both auxiliary-operated ADS valves and spring-lift SRVs. Requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Articles NB 7510, "Safety, Safety Relief, and Relief Valves," NB 7520, "Pilot Operated Pressure Relief Valves," and NB 7540, "Safety Valves or Pilot Operated Pressure Relief Valves with Auxiliary Actuating Devices" ensure that a malfunction of the auxiliary actuating device does not compromise the spring-lift mode SRV function.

In response to RAI 5.2-27, the applicant explained that that "only one of 18 SRVs is required to open to prevent exceeding the ASME limit in the ASME overpressure protection event. The other 17 SRVs are needed for the ATWS event." The applicant included this information in of DCD Tier 2, Revision 3, Section 5.2.2.3.2. Therefore, Revision 3 of GTS 3.4.1 required the safety mode of just two SRVs (which can be any two of the 18 SRVs) to be operable and allowed one required SRV to be inoperable for 14 days. In addition, DCD Revision 3 addressed separately the ADS and GDCS in LCO 3.5.1 and LCO 3.5.2, respectively. DCD Revision 1 had previously addressed both of these systems in LCO 3.5.1. GTS 3.5.1 proposed to allow one ADS-SRV and one DPV to be concurrently inoperable until the next entry into Mode 2 or 4 from Mode 5, and, as in DCD Revision 1, two ADS-SRVs and two DPVs to be concurrently inoperable for 14 days.

In RAI 16.2-34 S01 the staff asked the applicant to provide the following information:

1. Justify the change from four to two SRVs with an operable safety mode required by LCO 3.4.1.
2. Explain the methodology for periodic testing of the non-ADS SRVs, including a discussion of why the testing is not included in a TS SR.
3. Correct an apparent error in DCD Tier 2, Revision 3, Table 5.2-2, in which Note (1) indicates that "The SRVs also perform the automatic depressurization function." The non-ADS SRVs do not perform an automatic depressurization function. The superscript "(1)" should be deleted from the "Number of Valves" heading. This superscript should be relocated following "ADS SRV" and "DPV," since only the ADS SRVs and DPVs perform the automatic depressurization function, and should state, "(1) The ADS SRVs and DPVs also perform the automatic depressurization function."

RAI 16.2-34 was being tracked as an open item in the SER with open items.

In response GEH clarified the terminology, which it had introduced in DCD Revision 4, of the various safety valves and ADS valves in the ESBWR design, as follows:

<u>Previous Name</u>	<u>New Name</u>	<u>LCO</u>	<u>Number Required</u>
ADS-SRV	SRV	3.4.1 (safety mode)	2
Non-ADS SRV	SV	None	8
ADS-SRV	SRV	3.5.1 (ADS function)	10
DPV	DPV	3.5.1 (ADS function)	8

This change simplified LCO 3.4.1 by clearly requiring the safety mode of two of the ten SRVs to be operable, to maintain function in case a single failure renders the safety mode of one required SRV inoperable, and specifically not requiring operability of the eight SVs, so that the associated SRs for the safety mode lift settings of the SRVs are not required for the SVs. The safety mode lift settings for the SVs are maintained in accordance with the inservice testing (IST) program, which is acceptable. Based on DCD Tier 2, Revision 4, Section 5.2.2.3, the most severe overpressurization event for the ESBWR is the MSIV closure, with scram occurring on high flux, (i.e., MSIV closure with flux scram [MSIVF] special event). The evaluation of the MSIVF event shows that only one SRV is required to open to prevent exceeding the ASME limit, as stated in DCD Tier 2, Section 5.2.2.3.2. Therefore, to satisfy the design-basis overpressure event (and to account for single failure), TS 3.4.1 requires the safety mode of two SRVs to be operable. LCO 3.4.1 does not require the relief mode (ADS mode) of the SRVs to be operable, as discussed in the response to RAI 5.2-19, which explains why the ESBWR design does not include the automatic power-actuated pressure relief function, which is incorporated in the BWR/6 STS 3.4.4 requirements for SRVs (seven SRVs in safety mode and seven other SRVs in relief mode must be operable). Therefore, LCO 3.4.1 is acceptable. The 14-day completion time to restore an inoperable required SRV to operable status is consistent with the BWR/6 STS 3.4.4 actions. Therefore, GTS 3.4.1 is acceptable. Based on the above, Parts 1 and 2 of RAI 16.2-34 S01 are resolved. The applicant resolved Part 3 by removing the note in question as unnecessary detail and by changing the nomenclature to SRV and SV. The discussion of RAI 16.2-32 addresses the resolution of the action requirement issue for ADS valves (SRVs and DPVs). Therefore, RAI 16.2-34 is resolved.

RAI 16.2-35 The staff requested that the applicant describe how squib valve explosive charge actuation testing will be ensured during plant operation. In response, the applicant stated that SLC, ADS, and GDSCS squib valves must meet the requirements of 10 CFR 50.55a. Specifically, 10 CFR 50.55a requires that these valves be subject to an IST program performed in accordance with the latest approved version of American Society of Mechanical Engineers/American National Standards Institute (ASME/ANSI) Operations and Maintenance Standards, Part 10 (OM-10), "Inservice Testing of Valves in Light-Water Reactor Power Plants." DCD Tier 2, Revision 3, Table 3.9-8, provides the details for implementing the squib valve IST program. GEH also revised DCD Tier 2, Revision 3, Section 16B, by removing the brackets from around "Inservice Test Program" in the bases for SR 3.5.1.3, SR 3.5.1.4, and SR 3.5.2.3. The IST program, in conjunction with TS SRs to verify squib valve firing circuit continuity every 31 days, provides an acceptable means for ensuring that squib valve operability is maintained during plant operation. Therefore, RAI 16.2-35 is resolved.

RAI 16.2-36 GTS SR 3.5.3.1 (Modes 5 and 6) requires the combined water volume of required GDSCS pools to be verified every 24 hours. The GTS bases state that SR 3.5.3.1 will verify that the water level in each of the GDSCS pools is greater than or equal to the specified limit for operability. In RAI 16.2-36, the staff asked the applicant to clarify the differing requirements (i.e., combined GDSCS pool water volume versus GDSCS pool water level) between SR 3.5.3.1 and the associated bases. In response, the applicant proposed revising the bases for

SR 3.5.3.1 to reflect the GDCS pool operability requirements as specified in the surveillance. The change to the bases, which state, “this SR requires verification every 24 hours that the combined water volume in GDCS pools associated with Operable GDCS injection branch lines is greater than or equal to the specific limit,” is acceptable. Therefore, RAI 16.2-36 is resolved. DCD Revision 5 changed the bases of the corresponding SR 3.5.3.2 to state, “this SR requires verification that the water level in each of the GDCS pools is within the specified limit.” DCD Revision 5 also changed the bases of LCO 3.5.3 to state, “this LCO requires two injection subsystem branch lines associated with each of the three GDCS pools (i.e., six injection subsystem branch lines) and two equalizing lines.” For the reasons described in the evaluation of RAI 16.2-94, these changes are acceptable.

RAI 16.2-37 The staff asked the applicant to justify the different acceptance criteria for GDCS pools in SR 3.5.2.1 for Modes 1, 2, 3, and 4 and in SR 3.5.3.1 for Modes 5 and 6. Specifically, SR 3.5.2.1 requires that each GDCS “pool water level” be verified every 12 hours, and SR 3.5.3.1 requires that the “combined water volume of required GDCS pools” be verified every 24 hours. In response, the applicant stated that the GDCS pool water level is verified in GTS SR 3.5.2.1 to ensure that the volume of water assumed in the accident analysis for Modes 1, 2, 3, or 4 is met. The minimum combined water volume specified in GTS SR 3.5.3.1 is equal to the volume of the two smaller GDCS pools when each is filled to the normal operating level. This minimum volume, therefore, provides sufficient combined water inventory to fulfill makeup requirements for Modes 5 or 6, while still allowing any one of the three GDCS pools to be drained for maintenance or inspection. This is acceptable since GDCS pool operability is based on maintaining a combined water inventory, as assumed in the accident analysis. Thus, the criteria may be based on either minimum pool water level or minimum pool volume. Therefore, RAI 16.2-37 is resolved. For the reasons described in the evaluation of RAI 16.2-94, DCD Revision 5 changed the corresponding SR 3.5.3.2 and LCO 3.5.3.a to require all three GDCS pools to maintain a level in each pool of greater than or equal to 6.5 m (21.3 ft).

RAI 16.2-38 The staff requested that the applicant provide a detailed explanation for GDCS pool operability in the bases for GTS 3.5.2, including factors such as air space communication with the drywell, pool debris, and water chemistry. In response, the applicant proposed revising the bases for GTS 3.5.2 to include the statement, “OPERABILITY of each GDCS injection branch line requires that the water level in the associated GDCS pool be within the limit specified by GTS SR 3.5.2.1.” The applicant also stated that it did not include GDCS pool airspace-to-drywell communication as a GTS requirement since no mechanism exists for isolating this connection. GDCS pool water chemistry verification is not included as a GTS requirement since it does not meet any criteria in 10 CFR 50.36. GDCS pool debris and protective coatings are controlled consistent with specific guidance, as referenced in the DCD. The staff considers the bases changes acceptable. Therefore, RAI 16.2-38 is resolved.

RAI 16.2-39 The staff asked the applicant to provide a detailed explanation of the meaning of “required GDCS pools” in GTS SR 3.5.3.1. In response, the applicant stated that LCO 3.5.3, “Gravity-Driven Cooling System (GDCS) - Shutdown,” and GTS SR 3.5.3.1 credit the minimum number of GDCS branch lines and combined GDCS pool volume that can be injected to ensure GDCS operability. The applicant revised GTS LCO 3.5.3 and SR 3.5.3.1 and bases to reflect this response. In DCD Revision 4, the applicant further clarified this surveillance, which was renumbered as SR 3.5.3.2, to explicitly state the combined GDCS pool water volume required to be available for injection through the four associated GDCS injection branch lines that are required to be operable by LCO 3.5.3. For reasons described in the evaluation of RAI 16.2-94, DCD Revision 5 changed the corresponding SR 3.5.3.2 and LCO 3.5.3.a to require six injection branch lines - two from each GDCS pool - and all three GDCS pools to maintain a level in each

pool of greater than or equal to 6.5 m (21.3 ft). These changes, along with the associated changes to the bases for LCO 3.5.3 and SR 3.5.3.2, as described in the discussion of RAI 16.2-36, are acceptable. Therefore, RAI 16.2-39 is resolved.

RAI 16.2-40 The staff requested that the applicant justify its decision not to specify a GDCS pool operability temperature limit in GTS 3.5.2. The ESBWR accident analysis for peak containment pressure assumes that the initial GDCS water and gas space temperatures are in equilibrium with the drywell air temperature. In response, the applicant stated that the analysis assumed an initial temperature of 46.1 degrees C (115 degrees F) for both the drywell gases and the GDCS pool water. In addition, GTS 3.6.1.5 ensures that drywell air temperature is maintained less than or equal to this limit. The applicant further stated that the drywell air temperature limits GDCS pool temperature because there is no mechanism that could cause GDCS pool temperature to rise above drywell air temperature.

In RAI 16.2-40 S01, the staff asked that the applicant explain in further detail how the GDCS pool temperature is to be adequately determined to be less than or equal to 46.1 degrees C (115 degrees F) by referencing an equilibrium with average drywell air temperature, because temperatures in the upper levels of the drywell (i.e., in the space surrounding the GDCS pool walls and air space) may be potentially and consistently greater than 46.1 degrees C (115 degrees F), although the drywell average temperature is below this value. RAI 16.2-40 was being tracked as an open item in the SER with open items. In response, GEH stated that “the normal operating containment ventilation design utilizes upper and lower drywell air handling units, which minimizes thermal stratification and the general uncertainties associated with severe temperature gradients. Therefore, it is not necessary to measure separately the GDCS pool water or air temperatures, to ensure the critical initial conditions of the containment and ECCS performance analyses are being maintained.” GEH also stated that analyses performed in response to RAI 6.2-64 show that “initial GDCS pool water temperature does not have a significant impact on the containment and ECCS performance analyses. Therefore, there is no required GDCS pool water temperature band necessary to ensure that the acceptance criteria of the containment and ECCS performance analyses are met. As such, 10 CFR 50.36(c)(2)(ii)(B), Criterion 2, is not applicable to this variable, and there is no requirement for a technical specification to monitor GDCS pool water temperature.”

DCD Revision 4 revised LCO 3.6.1.5 to require that drywell temperature be less than or equal to 57.2 degrees C (135 degrees F), instead of less than or equal to 46.1 degrees C (115 degrees F). And, in DCD Revision 5, GEH revised LCO 3.6.1.5 again to require the drywell temperature be less than or equal to 65.6 degrees C (150 degrees F). In RAI 16.2-40 S02, the staff asked GEH to provide a SR for GDCS pool temperature in GTS 3.5.2 that is consistent with the highest and lowest initial temperatures and pressures in the drywell and temperatures in the GDCS pools assumed in the analyses of design-basis events. The staff stated that, although an initial drywell temperature of 65.6 degrees C (150 degrees F) is consistent with the DCD Revision 5 analysis assumptions, specifying a temperature limit of 65.5 degrees C (150 degrees F) in GTS LCO 3.6.1.5 implies that this is an acceptable temperature for normal operation. The staff asked GEH to explain why the TS should not require taking action to deal with degraded drywell cooling at drywell temperatures much lower than this. In response, GEH stated that the “expected steady state GDCS pool temperature is expected to be less than 135 °F [57.2 °C] due to the drywell cooling system (DCD Tier 2, Table 9.4-12) maintaining drywell temperature at or less than 135 °F [57.2 °C] with a maximum of 150 °F [65.5 °C] (DCD Tier 2, Table 6.2-2). Maintaining a lower drywell temperature would provide an unwanted load on the drywell cooling system and lower the operating efficiency of the plant.” In addition, GEH stated that “using TRACG for the limiting cases in DCD Tier 2, Sections 6.2 (MSLB) and 6.3

(ICS drain line break) demonstrate that higher initial GDCS pool water temperatures do not have a significant impact on the containment and ECCS performance.” GEH also added the following to the “Background” section of the bases for GTS 3.5.2 and DCD Tier 2, Section 6.3.2.8.3 regarding the DCD safety evaluation of the ADS:

Although the nominal and bounding containment performance analyses are performed at an initial condition of 46.1°C (115°F) for the GDCS pool water temperature, additional analyses assuming GDCS pool water temperature as high as 65.5°C (150°F) were performed. These analyses demonstrate the relative insensitivity of the calculated peak containment pressure and temperature and reactor pressure vessel long-term water level after a DBA for increased GDCS pool water initial temperature.

Based on the stated analysis results, GEH concluded that monitoring the GDCS pool temperature is not required. RAI 16.2-40 is resolved based on the GEH responses, the results of the additional analyses, and changes to DCD Section 6.3.2.8.3 and the “Background” section of the bases for GTS 3.5.2.

RAI 16.2-41 The staff requested that the applicant justify its decision not to include limits on the ICS subcompartment pool water level and temperature in GTS 3.5.4, “Isolation Condenser System (ICS) - Operating.” In response, the applicant explained that GTS 3.5.4 does not include a surveillance to verify IC subcompartment level and temperature because GTS 3.5.4 and 3.7.1, “IC/PCCS Pools,” together specify adequate surveillances to ensure that there is sufficient water in the IC/PCCS pools, with average temperature at or below the required limit, to provide the required 72-hour heat sink. As specified in DCD Revision 6, and as revised by the applicant’s response to RAI 16.2-189, these surveillances include the following:

- SR 3.5.4.4, to verify once every 24 months that each ICS subcompartment manual isolation valve is locked open, including each manual isolation valve between an ICS sub-compartment and its associated inner expansion pool;
- SR 3.7.1.1, to perform once every 12 hours a channel check on each required IC/PCCS expansion pool level instrumentation channel;
- SR 3.7.1.2, to verify once every 24 hours the required level in the IC/PCCS inner expansion pools;
- SR 3.7.1.3, to verify once every 24 hours the required level in the equipment pool and reactor well (the equipment pool and reactor well are connected through the opening for the reactor well-to-equipment pool gate);
- SR 3.7.1.4, to verify once every 24 hours that the average water temperature in available IC/PCCS pools (which include the IC/PCCS inner expansion pools, the ICS and PCCS sub-compartments, the equipment pool, and the reactor well) is within limit;
- SR 3.7.1.5, to verify once every 31 days that supply pressure to each IC/PCCS inner expansion pool-to-equipment pool cross-connect valve accumulator is within limit;
- SR 3.7.1.6, to verify once every 31 days continuity of the DPS initiator and two [required] safety-related initiators on each IC/PCCS inner expansion pool-to-equipment pool cross-connect valve;
- SR 3.7.1.7, to perform once every 31 days a channel functional test on each required IC/PCCS expansion pool level instrumentation channel;

- SR 3.7.1.8, to verify once every 24 months that each manual isolation valve between the partitions in each IC/PCCS inner expansion pool is locked open;
- SR 3.7.1.8, to verify once every 24 months that each manual isolation valve on each inner expansion pool-to-equipment pool line is locked open;
- SR 3.7.1.9, to verify once every 24 months that the reactor well-to-equipment pool gate is not installed;
- SR 3.7.1.10 to verify once every 24 months that each IC/PCCS inner expansion pool-to-equipment pool cross-connect valve actuates on an actual or simulated automatic initiation signal;
- SR 3.7.1.11, to perform once every 24 months a channel calibration on each required IC/PCCS inner expansion pool level instrumentation channel consistent with Specification 5.5.11, "Setpoint Control Program (SCP)";
- SR 3.7.1.12, to perform once every 24 months a LSFT on each required division of the IC/PCCS inner expansion pool-to-equipment pool cross-connect actuation logic;
- SR 3.7.1.13, to verify that each IC/PCCS pool subcompartment has an unobstructed path through the moisture separator to the atmosphere once every 48 months on a staggered test basis for the flow path associated with each of the two moisture separators.

Verifying IC/PCCS inner expansion pool level ensures proper level in each ICS and PCCS condenser subcompartment because each subcompartment is connected to its inner expansion pool by means of a locked open manual isolation valve located near the bottom of the subcompartment.

Regarding the lack of limits on ICS subcompartment water temperature in GTS 3.5.4, the applicant indicated that no limits are required to be specified because initial ICS subcompartment temperature does not affect the analysis results for the postulated design-basis events of a LOCA, SBO, and RPV isolation. However, the IC/PCCS pool average temperature is an assumption in the safety analysis; therefore it is limited by GTS 3.7.1 in SR 3.7.1.4. The staff concludes that the GTS requirements for the IC/PCCS pools will provide adequate assurance of the operability of the heat sink to support ICS and PCCS operability. Therefore, RAI 16.2-41 is resolved.

RAI 16.2-42 The staff asked the applicant to justify why it did not include in GTS 3.5.4, "Isolation Condenser System (ICS) - Operating," a SR similar to the approved Dresden TS SR 3.5.3.4, which requires verifying every 60 months that the ICS is capable of removing design heat load. In response, the applicant stated that Revision 3 of GTS 3.5.4, "Isolation Condenser System (ICS) - Operating," added a SR to verify the heat removal capability of each IC train. The associated GTS bases state that this surveillance will demonstrate the heat removal capability of each IC train to satisfy the design requirements specified in DCD Tier 2, Revision 9, Chapter 5. The surveillance frequency for the IC heat capacity testing is "Prior to exceeding 25% RTP if not performed in the previous 24 months on a staggered test basis." This frequency will ensure timely identification of any degradation in ICS performance by testing one IC train every 24 months, so that each IC train is tested once every 8 years. The staff finds this frequency acceptable. In DCD Revision 3, the surveillance frequency was enclosed in brackets, pending supporting changes to DCD Tier 2, Section 5.4.6.4, which the applicant proposed in response to RAI 5.4-52. In Revision 4 to GTS 3.5.4, the applicant removed the brackets from the frequency for this SR, coincident with associated changes to DCD Tier 2, Section 5.4.6.4. In

DCD Revision 9, the applicant added SR 3.5.5.6 to require meeting SR 3.5.4.6 for the ICS trains required operable by LCO 3.5.5. With the addition of SR 3.5.4.6 and SR 3.5.5.6 and associated bases, RAI 16.2-42 is resolved.

RAI 16.2-73 The staff requested that the applicant justify limiting the applicability of ESBWR GTS 3.5.3, "GDCS - Shutdown," to Mode 6, except with the buffer pool gate removed and the water level greater than or equal to 7.01 m (23.0 ft) over the top of the RPV flange. In response, the applicant indicated that the RWCU/SDC system provides adequate DHR capability, with the FAPCS providing backup DHR. During an unlikely event, such as a loss of inventory coincident with loss of the RWCU/SDC system, the water volume above the top of active fuel (TAF) but below the vessel flange provides adequate time to align makeup water from the CRD, FAPCS, firewater, or condensate pumps. The applicant relies heavily on the RWCU/SDC system and FAPCS to support shutdown DHR. The staff questioned why there are no availability controls on the RWCU/SDC system and the referenced alternate makeup systems because these systems share dependencies on support systems, such as nonsafety electrical power. The diesel firewater pump is not dependent on electrical power, but it was unclear to the staff how makeup water from this system would reach the reactor vessel without an intact refueling cavity.

In RAI 16.2-73 S01, the staff recommended establishing short-term availability controls for the RWCU/SDC system, expanding the operability requirement for the GDCS to include Mode 6 for all refueling cavity water levels, or providing analysis demonstrating that sufficient water inventory would remain above TAF following a shutdown LOCA for greater than 72 hours. The staff asked the applicant to pursue the recommended analysis.

In RAI 16.2-73 S02, the staff replaced its request for an analysis with a request for a detailed description of the proposed makeup water transfers and a corresponding markup of the FAPCS availability controls. RAI 16.2-73 was being tracked as an open item in the SER with open items. In response, GEH stated that it had performed an analysis of the passive DHR from the RPV during the onset of a refueling outage. The following were among the assumptions used in the analysis:

- Analysis begins 24 hours after shutdown.
- All fuel is kept in the RPV (none in the buffer pool deep pit).
- Available water is limited to the RPV, reactor cavity, and shallow buffer pool.

GEH stated that the "analysis shows that the water above the core will heat up and begin to boil if forced cooling is lost. After 72 hours under the most limiting heat load, there is still sufficient water to keep the core covered and maintain an adequate level of shielding." Based on the stated results of this analysis, the staff concludes that, in Mode 6 with the reactor cavity flooded up, sufficient water inventory exists to passively provide DHR and protect the fuel until active nonsafety systems become available to perform the DHR function and provide RPV inventory makeup. Therefore, RAI 16.2-73 is resolved.

RAI 16.2-74 The staff requested that the applicant clarify the basis for not including an operability requirement for a DHR method in the refueling mode with the head fully detensioned or removed. In response, the applicant stated that the nonsafety-related RWCU/SDC system provides the normal method of DHR in Modes 5 and 6, but that the criteria of 10 CFR 50.36(c)(2)(ii) did not require establishing an LCO for this system. The applicant further stated that, in Mode 6 with a water level less than or equal to 7.01 m (23.0 ft) over the top of the RPV flange (low water level), the GDCS provides the safety-related backup DHR method. Furthermore, the GDCS requires adequate reactor vessel venting to maintain its operability.

The RPV must remain depressurized following a loss of DHR in order for the GDCS to inject cooling water into the vessel. When in Mode 6 with the water level greater than 7.01 m (23.0 ft) over the top of the RPV flange (high water level) and the new fuel pool gate removed (i.e., with the RPV flooded), the large amount of water stored above the core provides the safety-related backup DHR capability.

In contrast, the bases of STS 3.9.8, "RHR - High Water Level," and 3.9.9, "RHR - Low Water Level," describe the safety-related residual heat removal (RHR) system as the primary DHR method in Mode 6. At a high water level, the large coolant inventory provides a heat sink as backup to the RHR system. In addition, the bases for STS 3.5.2, "ECCS-Shutdown," describe the injection capability of the large volume of water above the vessel as providing sufficient coolant inventory in Mode 6 to allow time for operators to take action to terminate the coolant inventory loss before uncovering the fuel in the event of an inadvertent RPV draindown.

From its review of the applicant's response, the staff concluded that the GTS did not explicitly specify an adequate RPV vent path in either Mode 5 or in Mode 6 before removal of the vessel head. The staff believes that the GTS should explicitly require an adequate RPV vent path; simply describing this GDCS operability requirement in the bases for GTS 3.5.3 will not ensure GDCS operability in Mode 5 and in Mode 6 before removal of the vessel head.

In RAI 16.2-74 S01, the staff requested that the applicant provide a GTS requirement for a RPV vent path as part of GDCS operability with the unit in Mode 5 and in Mode 6 before removal of the vessel head. In addition, the staff requested that the applicant provide an availability control for the RWCU/SDC system. In response, the applicant proposed a new SR for GTS 3.5.3 to "verify availability of RPV venting capacity sufficient to allow GDCS injection following loss of decay heat removal capability," with a frequency of once every 24 hours, which was less restrictive than the frequency of the corresponding surveillance in the STS (see NUREG-1431, Revision 3.0, "Standard Technical Specifications - Westinghouse Plants," and specifically, SR 3.4.12.5, "Verify required RCS vent \geq [2.07] square inches open," with a frequency of "12 hours for unlocked open vent valve(s) AND 31 days for other vent path(s)"). The applicant did not propose an availability control for the RWCU/SDC function.

During a subsequent discussion with the applicant, the staff suggested that the SR was actually an indirect expansion of the ADS LCO 3.5.1 applicability to include Modes 5 and 6 when ADS is needed to support GDCS operability in the event of a loss of DHR. This is because meeting the proposed SR in Mode 5 or 6 (without an adequate vent path) would require making the ADS operable to provide the necessary vent path. The staff preferred revising the applicability of the ADS LCO to the applicant's proposal of a new SR in the shutdown GDCS specification. The staff also pointed out that other GTS changes would be needed, such as changing ECCS instrumentation ADS function applicability.

The staff included these comments in RAI 16.2-74 S02, which was being tracked as an open item in the SER with open items. In response, the applicant proposed revising GTS SR 3.5.3.1 to "verify operability of sufficient ADS capacity to support assumed GDCS injection following loss of DHR capability," and adding a GTS 3.5.3 action requirement for an inoperable GDCS due to insufficient venting capacity (i.e., due to the inoperability of a required ADS support function). The applicant also proposed to revise GTS 3.3.5.2, "ECCS Actuation," to require operability of the ADS actuation instrumentation function in Mode 5 and in Mode 6 with the RPV head in place.

In RAI 16.2-74 S03, the staff asked how an operator would determine the number of required SRVs and DPVs as a function of the decay heat load in order to meet the proposed GTS 3.5.3 action requirement for insufficient vent capacity and the proposed surveillance to verify sufficient vent capacity. In response, GEH proposed to revise the action requirement to state, "Establish RCS vent path(s) with relief capacity equivalent to required ADS valves," in 4 hours, and the surveillance to state, "Perform applicable LCO 3.5.1, 'Automatic depressurization system (ADS) - Operating,' SRs for ADS valves required for relief capacity equivalent to 4 depressurization valves (DPVs)," with a frequency of "In accordance with applicable SRs." Subsequently, in DCD Revision 5, the applicant increased the number of required DPVs to six in SR 3.5.3.1 to provide an allowance for DPV failures. The staff finds that this change is acceptable because it will ensure that sufficient ADS valves are operable to support GDCS operability as required by GTS 3.5.3 even in the event of a failure of one of the required ADS valves. In DCD Revision 6, this SR was combined with the verification in GTS SR 3.5.3.5 that each required GDCS valve and ADS valve actuates on an actual or simulated automatic initiation signal. This change in presentation did not alter the proposed requirement for verifying reactor vessel relief capacity in Modes 5 and 6, and is acceptable because it is only an administrative change.

GTS 3.5.3 requires operability of two injection system branch lines for each of the three GDCS pools (which must have specified minimum volume), two equalizing subsystem trains (which must have specified minimum suppression pool volume), and ADS valves with relief capacity equivalent to six DPVs. Even in the event of any single failure, these requirements will ensure that sufficient water will be automatically injected into the RPV following a loss of DHR capability or a loss of RPV inventory (a LOCA or an inadvertent vessel draindown event) while in Mode 5, Mode 6 with the RPV head in place, or Mode 6 with water level less than 7.01 m (23.0 ft) above the top of the RPV flange. Therefore, GTS LCO 3.5.3 is acceptable and RAI 16.2-74 is resolved. In RAI 16.2-173, discussed below, the staff noted an additional concern regarding the SR to verify reactor vessel relief capacity in Modes 5 and 6.

RAI 16.2-94 In response to the staff's request, GEH confirmed that the level of 6.5 m (21.3 ft) in each GDCS pool, specified in SRs 3.5.2.1 and 3.5.3.2, is equivalent to the minimum total drainable inventory of 1,636 m³ (57,775 ft³), as stated in DCD Tier 2, Revision 5, Table 6.3-2 for three GDCS pools at low water level (i.e., 6.5 m [21.3 ft]). In DCD Revision 5, GEH revised GTS 3.5.3 to also require the minimum total drainable inventory for three GDCS pools at low water level (i.e., 6.5 m [21.3 ft]). DCD Revision 5 superseded the GEH response to RAI 16.2-94 S01, in which SR 3.5.3.2 was to specify just the combined drainable inventory in the two smaller GDCS pools corresponding to a water level of 6.5 m (21.3 ft) and volume of 986.8 m³ (34,848 ft³). The applicant based the changes it made to the GTS 3.5.3 LCO (to require two injection subsystem branch lines associated with each GDCS pool and two equalizing subsystem trains) and actions (to ensure capability of two methods of injecting a combined water volume equivalent to required GDCS pool volume and required suppression pool volume within 4 hours) in DCD Revision 5 on achieving consistency with DCD Tier 2, Section 15.2.2.9, regarding a loss of normal shutdown cooling, and GEH's response to RAI 19.1-96 S01. Based on these changes and confirmation that the specified minimum levels in the three GDCS pools are correct, RAI 16.2-94 is resolved.

RAI 16.2-95 The staff requested that the applicant add a system flow test surveillance to GTS 3.5.2, "GDCS - Operating," as a part of a system-level operability test program, such as that specified in the AP1000 design certification GTS for the core makeup tanks and the in-containment refueling water storage tank with a 10-year frequency. In response, GEH stated that such a system-level operability test program for the GDCS is not warranted for the following reasons:

- Preoperational testing and completion of ITAAC for the GDACS will verify that the injection subsystem and the equalizing subsystem are capable of providing sufficient flow to maintain reactor vessel water level one meter above TAF for 72 hours following a design basis LOCA. (See Section 6.3 of this report for discussion of RAI 6.3-18 S01 regarding GDACS ITAAC listed in DCD Tier 1, Table 2.4.2-3.)
- Cleanliness controls will be implemented in accordance with RG 1.39, "Housekeeping Requirements for Water-Cooled Nuclear power Plants," and will prevent degradation of GDACS performance due to accumulation of debris during normal operation and maintenance, to ensure that each GDACS injection and equalizing line has a flow loss coefficient that is less than that modeled in the TRACG code.
- GTS 3.5.2 was revised with the addition of SR 3.5.2.4 to "Verify the flow path for each GDACS injection branch line is not obstructed" and SR 3.5.2.5 to "Verify the flow path for each GDACS equalizing line is not obstructed." These SRs have a Frequency of 24 months on a staggered test basis for each pair of injection branch lines and for each equalizing line, respectively. (The applicant also added SR 3.5.3.6 to require meeting these SRs to meet GDACS operability requirements of LCO 3.5.3.). These surveillances are consistent with the testing listed in DCD Tier 2, Revision 9, Table 6.3-3, which uses flow through the system test lines to open and close the GDACS check valves and to show that there is no obstruction of the RPV nozzles. DCD Tier 2, Revision 9, Table 3.9-8 states that the eight GDACS injection branch line check valves and four equalizing line check valves are tested every 24 months (refueling outage frequency). Table 6.3-3 also states that flushing will be performed using test connections during each refueling outage to (1) functionally test the eight injection branch line check valves and four equalizing line check valves, (2) remove any possible plugging of the four injection lines, eight injection branch lines, and the venturis within each GDACS-RPV nozzle, and (3) prevent crud build up in the deluge lines.

Based on the above, RAI 16.2-95 is resolved.

RAI 16.2-96 The staff requested that GEH add SRs to GTS 3.5.2 corresponding to the test items listed in DCD Tier 2, Table 6.3-3, or explain why it did not propose such surveillances. These items include (1) functional testing of GDACS check valves, (2) explosive testing for GDACS squib valve initiators, (3) flushing of GDACS injection lines to remove possible plugging, (4) flushing of the GDACS injection nozzles, and (5) flushing of the deluge lines. In response, GEH stated that the IST program requires functional testing of the check valves and testing of squib valve initiators. The provisions of 10 CFR 50.55a and GTS 5.5.5 require the IST program. Tests required by the IST program must be met to establish component and system operability, unless a technical evaluation by the Licensee has determined that the component is degraded but operable (see RIS 2006-17), and need not be specified again as TS SRs. GEH also stated that "requirements for system flushing, unless used explicitly for removing obstructions that could interfere with system performance, are cleanliness controls." The staff considers that the flushing requirements listed in Table 6.3-3 are preventive maintenance requirements and, therefore, need not be specified as TS SRs. However, failure to perform this maintenance during a refueling outage would require a system operability assessment (see RIS 2006-17) to verify that SR 3.5.2.4 for the injection and equalizing lines and availability control SR

(ACSR) 3.5.1.6 for the deluge lines are still met. For the reasons stated, the staff concludes that the test items listed in Table 6.3-3 need not be GTS SRs. Therefore, RAI 16.2-96 is resolved. In DCD Tier 2, Revision 4, GEH changed the title of Table 6.3-3 from “Surveillance Requirements” to “Inservice Testing and Maintenance” to clarify the nature of the items listed in the table.

RAI 16.2-173 In DCD Revision 5, SR 3.5.3.1 stated, “Perform applicable LCO 3.5.1, ‘Automatic Depressurization System (ADS) - Operating,’ SRs for ADS valves required for relief capacity equivalent to 6 depressurization valves (DPVs).” The staff asked GEH to clarify this SR by explaining which GTS 3.5.1 SRs would be applicable. In its response, GEH added explicit SRs to GTS 3.5.3 corresponding to the “applicable” SRs in GTS 3.5.1. As presented in DCD Revision 6, these SRs include the following:

- SR 3.5.3.3, verification that SRV accumulator supply pressure is ≥ 2.41 MPaG (350 psig) once per 31 days (equivalent of SR 3.5.1.1)
- SR 3.5.3.4, verification of the continuity of two initiators associated with dc and Uninterruptible ac Electrical Power Distribution Divisions required by LCO 3.8.7, ‘Distribution Systems - Shutdown,’ for each required GDCS valve and for ADS valves required to support relief capacity equivalent to six DPVs once per 31 days (equivalent of SR 3.5.1.2)
- SR 3.5.3.5, verification that each required GDCS valve and ADS valve required to support relief capacity equivalent to six DPVs actuates on an actual or simulated automatic initiation signal once per 24 months (equivalent to SRs 3.5.1.3 and 3.5.1.4)

These SRs superseded the previous SR for verifying RCS relief capacity. The applicant also made conforming changes to the bases for GTS 3.5.3. The above changes to the SRs for GTS 3.5.3 provided the requested clarification to the previous SR for verifying RCS relief capacity. Therefore, RAI 16.2-173 is resolved.

RAI 16.2-188 The staff requested that GEH strengthen Action A of GTS 3.5.5 for the condition of one or more required ICS trains inoperable. As written in DCD Revision 5, Action A would permit all required ICS trains to be inoperable indefinitely, provided two methods of DHR are available. The staff pointed out that LCO 3.5.5 thus provided no meaningful requirement to keep two ICS trains operable in Mode 5 as the safety-related method of DHR, which would be needed if normal DHR was lost (i.e., loss of the RWCU/SDC system). In response, GEH changed Action A to be more consistent with the STS residual heat removal system action requirements and removed the allowance to operate indefinitely with no operable ICS trains by requiring the following four actions:

- Required Action A.1 (“immediately initiate action to restore required ICS trains to operable status”) removed the allowance to operate indefinitely with no operable ICS trains.
- Required Action A.2 (“within 1 hour and once per 24 hours thereafter, verify an alternate method of DHR is available for each inoperable required ICS train”) ensures that alternate methods of DHR are ready in case the RWCU/SDC system is lost.
- Required Action A.3 (“within 1 hour and once per 12 hours thereafter, verify at least one method of DHR is in operation”) and Required Action A.4 (“once per hour monitor reactor coolant temperature and pressure”) ensures effective control of reactor coolant temperature and pressure.

The revised action requirements are acceptable for the reasons stated. Therefore, RAI 16.2-188 is resolved.

The ESBWR ECCS GTS implement modified versions of the STS for ECCSs. The staff finds that these GTS are essentially equivalent to the STS for ECCS functions. For those cases in which the applicant has not included a GTS corresponding to a STS, ESBWR design differences provide sufficient justification for such an omission. Therefore, the ESBWR ECCS GTS and bases are acceptable.

16.2.9 ESBWR GTS Section 3.6, “Containment Systems”

The ESBWR containment boundary is formed by the inside surfaces of the following:

- Lower drywell floor and wall, which are beneath the RPV
- Upper drywell floor, including beneath the lower boundary of the drywell-to-suppression pool vent wall structure and the lower boundary of the wetwell (an enclosed space containing the suppression pool)
- Upper drywell wall (which includes the outer wall of the wetwell and the outer walls of the GDCS pools)
- Upper drywell ceiling, which includes the removable drywell head
- PCCS condenser, which is a closed loop extension of the containment pressure boundary

The GDCS pools are inside the drywell and are connected to the drywell by vents through the pools’ inside walls above the normal water level of the pools. The ESBWR suppression pool in the wetwell is connected to the upper drywell through horizontal vents to perform a pressure suppression function similar to the BWR/6 design. The ESBWR wetwell ceiling penetrations, each containing a drywell-to-wetwell vacuum breaker, connect the wetwell airspace above the suppression pool to the upper drywell.

In DCD Revision 4, GEH withdrew its intention (as stated in its response to RAI 16.0-1) to establish a GTS SR to test the float valves (which function as check valves) for the lower drywell spillover pipes because they were replaced with a passive design using spillover pipes without float valves, as described in Section 7.3 of licensing topical report (LTR) NEDE-33261P, Revision 1, “ESBWR Containment Load Definition.” On page 7-2 of this LTR, GEH states, “the twelve lower drywell spillover pipes have been replaced with small pipes directly connected to the main vents above the pool water line.” This new design for the spillover pipes does not require any float valves, obviating the need for a SR. GEH also removed language from DCD Tier 2, Revision 3, Section 6.2.1.1.2 regarding the previous spillover pipe design to reflect the new simplified design. The staff finds that a SR for the lower drywell spillover pipes is not necessary to ensure that they are capable of supporting containment operability because of the simplicity of their modified design.

The ESBWR GTS 3.6.1.1 through 3.6.1.5 are essentially identical to the corresponding STS requirements for primary containment, containment air locks, primary CIVs, and primary containment pressure and air temperature because the designs are functionally very similar. Major differences exist, however, between the ESBWR containment design and the BWR/6 Mark III containment design. These differences in the ESBWR design include the following:

- A PCCS is used instead of active systems, such as the BWR/6 RHR containment spray system and RHR suppression pool cooling system.
- An enclosing reactor building is used instead of a secondary containment with a standby gas treatment system.
- The drywell boundary forms most of the containment boundary, unlike the BWR/6 Mark III primary containment design in which the drywell boundary is not part of the primary containment boundary. For this reason, the ESBWR GTS do not contain LCOs corresponding to the STS for the drywell.

These differences are reflected in the ESBWR GTS Section 3.6 containment system specifications which correspond to the STS as follows:

<u>STS (# BWR/4)</u>	<u>ESBWR TS</u>	<u>ESBWR TS TITLE (*STS TITLE)</u>
3.6.1.1*	3.6.1.1	Containment (*Primary Containment)
3.6.1.2*	3.6.1.2	Containment Air Lock (*Primary Containment Air Locks)
3.6.1.3*	3.6.1.3	Containment Isolation Valves (*Primary Containment Isolation Valves)
3.6.1.4*	3.6.1.4	Drywell Pressure (*Primary Containment Pressure)
3.6.1.5*	3.6.1.5	Drywell Air Temperature (*Primary Containment Air Temperature)
3.6.1.6*	None	(*Low-Low Set Valves)
3.6.1.7*	None	(*Residual Heat Removal Containment Spray System)
3.6.1.7*#	None	(*Reactor Building-to-Suppression Chamber Vacuum Breakers)
3.6.1.8*#	3.6.1.6	Wetwell-to-Drywell Vacuum Breakers (*Suppression Chamber-to-Drywell Vacuum Breakers)
None	3.6.1.7	Passive Containment Cooling System (PCCS)
3.6.1.8*	None	(*Penetration Valve Leakage Control System)
3.6.1.9*	None	(*Main Steam Isolation Valve Leakage Control System)
3.6.2.1*	3.6.2.1	Suppression Pool Average Temperature (*same)
3.6.2.2*	3.6.2.2	Suppression Pool Water Level (*same)
3.6.2.3*	None	(*Residual Heat Removal Suppression Pool Cooling)
3.6.2.4*	None	(*Suppression Pool Makeup System)
3.6.2.5*#	None	(*Drywell-to-Suppression Chamber Differential Pressure)
3.6.3.1*	None	(*Primary Containment and Drywell Hydrogen Igniters)
3.6.3.2*	None	(*[Drywell Purge System])
3.6.3.2*#	3.6.1.8	Containment Oxygen Concentration (*Primary Containment Oxygen Concentration)
3.6.3.3*#	None	(*Containment Atmosphere Dilution System)
3.6.4.1*	3.6.3.1	Reactor Building (*[Secondary Containment])
3.6.4.2*	3.6.3.1	Reactor Building (*Secondary Containment Isolation Valves)
3.6.4.3*	None	(*Standby Gas Treatment System)
3.6.5.1*	None	(*Drywell)

<u>STS (# BWR/4)</u>	<u>ESBWR TS</u>	<u>ESBWR TS TITLE (*STS TITLE)</u>
3.6.5.2*	None	(*Drywell Air Lock)
3.6.5.3*	None	(*Drywell Isolation Valve[s])
3.6.5.4*	None	(*Drywell Pressure)
3.6.5.5*	None	(*Drywell Air Temperature)
3.6.5.6*	None	(*Drywell Vacuum Relief System)

The ESBWR design does not include a system corresponding to the BWR/4 containment atmosphere dilution system or the following BWR/6 systems:

- Low-low set valve system
- Penetration valve leakage control system
- MSIV leakage control system
- Primary containment and drywell hydrogen igniters
- Drywell
- Drywell purge system
- Standby gas treatment system
- Drywell isolation valves
- Drywell vacuum relief system

Accordingly, the GTS contain no LCOs for these systems. The GTS also contain no LCOs corresponding to the BWR/4 STS for the drywell-to-suppression chamber differential pressure. However, the ESBWR does include a CONAVS that includes redundant reactor building HVAC exhaust filtration trains for mitigating and controlling gaseous effluents from the reactor building. It also includes passive autocatalytic recombiners (PARs) in the upper and lower drywell to reduce the hydrogen concentration in containment. These nonsafety-related accident mitigation features are the subject of short-term availability controls in the ACM (AC 3.7.4 and AC 3.6.2, respectively), as described in Section 22.5.9 of this report. In addition, a PAR unit is attached to each vent line in the lower headers of the PCCS condensers. These PARs are required to be operable to support the PCCS operability requirements of LCO 3.6.1.7.

The GTS do not include an LCO for the drywell spray system, which is part of the nonsafety-related FAPCS. Unlike the BWR/6 RHR containment spray system, which is specified in STS 3.6.1.7, "RHR Containment Spray System," the ESBWR drywell spray system is not credited in any DBA analysis and is not assumed to function during the initial 72-hour period following a design-basis event. Drywell spray is a mode of FAPCS operation that is expected to be available for use following the initial 72-hour period after a LOCA to assist in postaccident recovery. During this mode of operation, to reduce the containment pressure, the FAPCS draws and cools water from the suppression pool and then sprays the cooled water into the drywell air space through a discharge line and ring header with spray nozzles mounted on the header. To prevent drywell spray actuation from reducing drywell pressure too much, a flow-restricting orifice limits the flow. Using an orifice instead of a throttle valve for this purpose reduces the need to specify, subsequent to initial system testing following construction, a GTS surveillance to periodically verify that the flow is limited as required. Therefore, omission of an LCO for the drywell spray system is acceptable.

The PCCS is designed to transfer heat from the containment drywell to the IC/PCCS pools following a LOCA. The PCCS consists of six independent condensers. Each condenser is a heat exchanger that is an integral part of the containment pressure boundary. The condensers

are located above the containment and are submerged in a large pool of water (IC/PCCS pool) that is at atmospheric pressure. Steam produced in IC/PCCS pools by boiling around the PCCS condensers is vented to the atmosphere. GTS 3.7.1, "Isolation Condenser (IC)/Passive Containment Cooling System (IC/PCCS) Pools," supports the PCCS in removing sufficient post-LOCA decay heat from the containment to maintain containment pressure and temperature within design limits for a minimum of 72 hours, without operator action.

Each of the six PCCS condensers consists of two identical modules. A single central steam supply pipe, open to the drywell at its lower end, directs steam from the drywell to the horizontal upper header in each module. Steam is condensed inside banks of vertical tubes that connect the upper and lower header in each module. The condensate collects in each module's lower header-and-drain volume and then returns by gravity flow to the GDCS pools. By being returned to the GDCS pools, the condensate is available to be returned to the RPV by way of the GDCS injection lines. Noncondensable gases that collect in the condensers during operation are purged to the suppression pool via vent lines. Hydrogen that may accumulate in a PCCS condenser lower header is removed as it passes through the PAR unit to enter the vent line. A loop seal in the GDCS drain line prevents backflow from the GDCS pool to the suppression pool.

During a LOCA, drywell pressure rises above the pressure in the wetwell (suppression pool). This differential pressure initially directs the high-energy blowdown fluids from the RCS break in the drywell through both the pressure suppression pool and through the PCCS condensers. As the flow passes through the PCCS condensers, heat is rejected to the IC/PCCS pool, thus cooling the containment.

The PCCS does not have instrumentation, control logic, or power-actuated valves, and the system does not need or use electrical power for its operation. This configuration makes the PCCS fully passive. Long-term effectiveness of the PCCS (beyond 72 hours) is supported by vent fans that are connected to each PCCS vent line and exhaust to the GDCS pool. The PCCS vent fans aid in the long-term removal of noncondensable gas from the PCCS for continued condenser efficiency. A GTS Section 3.6 LCO does not specify that the PCCS vent fans are to be operable because they do not meet any of the criteria in 10 CFR 50.36(c)(2)(ii). However, the ACM (AC 3.6.3) includes these fans, as described in Section 22.5.9 of this report.

The capabilities of the PCCS to condense steam from the drywell, drain the resulting condensate to the GDCS pools, and vent the noncondensable gases to the suppression pool are assured based on full-scale height testing during the development of the containment design for the simplified boiling-water reactor (SBWR). As discussed in Sections 6.2 and 21.6 of this report, the staff previously reviewed the SBWR test reports and found the ESBWR containment cooling design to be effective and acceptable. Consequently, the ESBWR design certification applicant proposed no periodic testing requirements in the GTS to physically demonstrate these capabilities because such testing was unnecessary and impractical. To ensure that the PCCS condensers, vent lines, and drain lines remain clear, GTS SR 3.6.1.7.3 requires verifying that both modules in each PCCS condenser have an unobstructed path from the drywell inlet through the condenser tubes to both the GDCS pool through the drain line and to the suppression pool through the vent line, every 24 months on a staggered test basis (i.e., each PCCS condenser and associated drain and vent lines will be verified to be unobstructed once every 12 years).

RAI 16.2-112 In DCD Revision 0, SR 3.6.1.1.2 states the following:

Verify drywell to suppression chamber differential pressure does not decrease at a rate greater than [6 mm water (0.25 inches water)] per minute tested over a [10] minute period at an initial differential pressure of [6.9 kPa (1 psi)].

This is consistent with BWR/4 STS SR 3.6.1.1.2, which states the following:

Verify drywell to suppression chamber differential pressure does not decrease at a rate $> [0.25]$ inch water gauge per minute tested over a [10] minute period at an initial differential pressure of [1] psid.

In DCD Revision 1, the applicant revised SR 3.6.1.1.2 to state, "Verify drywell to wetwell bypass leakage is less than $1 \text{ cm}^2 (A/\sqrt{K})$."

In DCD Revision 3, the applicant added SR 3.6.1.1.2 to verify that the feedwater flow isolation valve in-leakage is " $< \{ \text{lpm (gpm)} \}$ when tested at $\geq \{ \text{kPaD (psid)} \}$." The applicant renumbered the drywell-to-wetwell bypass leakage test as SR 3.6.1.1.3. In addition, GEH made a significant change in DCD Revision 3 to the drywell-to-wetwell bypass leakage test. Instead of measuring overall drywell-to-wetwell bypass area, the applicant proposed to measure only the leakage area through vacuum breaker lines. GEH revised SR 3.6.1.1.3 to state, "Verify the combined leakage rate through all vacuum breaker lines is $\leq 0.1 \text{ cm}^2 (1.0 \times 10^{-4} \text{ ft}^2) (A/\sqrt{K})$ when tested at $\geq \{ \text{kPaD (psid)} \}$."

The staff noted that this is inconsistent with the BWR/4 STS SR 3.6.1.1.2, quoted above, and BWR/6 STS SR 3.6.5.1.1, which states the following:

Verify bypass leakage is less than or equal to the bypass leakage limit.
However, during the first unit startup following bypass leakage testing performed in accordance with this SR, the acceptance criterion is $\leq [10\%]$ of the drywell bypass leakage limit.

In DCD Revision 3, the drywell-to-wetwell bypass leakage test only requires determining leakage through the vacuum breaker lines. But the BWR/4 and BWR/6 STS equivalent SRs require determining the total bypass leakage between drywell and wetwell (suppression chamber). Total bypass leakage is an assumption in the peak containment pressure calculation in DCD Tier 2, Revision 3, Section 6.2. In RAI 16.2-112, the staff asked the applicant to explain how it would ensure that the assumed total bypass leakage between the drywell and wetwell will not be exceeded during operation of the reactor. RAI 16.2-112 was being tracked as an open item in the SER with open items.

The staff also noted that SR 3.6.1.1.3 in DCD Revision 3 was not self-consistent because the side to the left of the less than or equal symbol (\leq) refers to a "leakage rate" (e.g., liters per minute), while the side to the right of the symbol has dimensions of area. In RAI 16.2-112, the staff asked the applicant to resolve the inconsistency.

In DCD Revision 4, the applicant revised SR 3.6.1.1.3 to state, "Verify the combined leakage rate through all vacuum breaker lines is less than or equal to the maximum established design A/\sqrt{K} ." However, this did not address the staff's concern about not testing for the overall suppression pool bypass leakage. In response to RAI 16.2-112, GEH resolved the noted inconsistency by explaining how, in industry practice, leakage is expressed in terms of area. The applicant also replaced SR 3.6.1.1.3 with the following three surveillances:

- 3.6.1.1.3 Verify each wetwell-to-drywell vacuum breaker and vacuum breaker isolation valve leakage is $\leq 15\%$ of design basis A/\sqrt{K} .
- 3.6.1.1.4 Verify total wetwell-to-drywell vacuum breaker and vacuum breaker isolation valve pathway leakage is $\leq 35\%$ of design basis A/\sqrt{K} .
- 3.6.1.1.5 Verify overall suppression pool bypass leakage is $\leq 50\%$ of design basis A/\sqrt{K} .

GEH stated that satisfactory performance of these SRs would ensure that the rate of suppression pool bypass leakage would remain below the maximum allowable suppression pool bypass leakage assumed in the analysis, thus ensuring that the containment design pressure will not be exceeded.

GEH stated that the maximum allowable suppression pool bypass leakage area is 2.0 cm^2 (0.31 in^2). In SR 3.6.1.1.5, the 50-percent criterion therefore corresponds to an area of 1.0 cm^2 (0.15 in^2). GEH proposed to perform this overall bypass leakage test in conjunction with, and at the frequency of, the containment integrated leak rate test (ILRT). As discussed in Section 6.2.1.1.3 of this report, in RAI 6.2-145, the staff questioned the proposed acceptance criterion and the test frequency. Based on the results of suppression pool bypass leakage surveillances at operating BWR facilities with Mark II and Mark III containments, the staff concluded that the 50-percent criterion for SR 3.6.1.1.5 is acceptable. However, the staff did not find the test history a sufficient basis for a 10-year test interval for the overall bypass leakage test. Because the staff had previously required plant-specific data to support such frequency relaxations at operating plants, the staff requested that GEH provide additional justification for the proposed frequency for the ESBWR test. In response, GEH proposed a 24-month frequency for the overall suppression pool bypass leakage test. The staff found this frequency acceptable because it is consistent with the frequency in the STS and for currently operating plants that have not gone to a longer test interval.

The staff reviewed the proposed acceptance criteria and frequencies of SR 3.6.1.1.3 for each wetwell-to-drywell vacuum breaker and vacuum breaker isolation valve leakage. The staff also reviewed the proposed criteria and frequencies of SR 3.6.1.1.4 for the total wetwell-to-drywell vacuum breaker and vacuum breaker isolation valve leakage. The staff found the acceptance criteria for these SRs to be acceptable because they are consistent with DCD Tier 2, Section 6.2. The staff found the 24-month frequency for these SRs acceptable because it is consistent with the frequency in the STS and the need to perform these surveillances under conditions that apply during a plant outage.

The staff concludes that the proposed SRs will ensure that drywell-to-wetwell bypass leakage will be maintained below the leakage assumed in the safety analysis and will support the conclusion that containment design pressure will not be exceeded following a design-basis event. They are therefore acceptable and RAI 16.2-112 is resolved.

Combustible Gas Control

The NRC revised 10 CFR 50.44, 10 CFR 50.34, and 10 CFR 52.47, and created a new rule, 10 CFR 50.46a, (see Volume 67, Page 50374, of the *Federal Register*; August 2, 2002). These changes were meant to risk-inform the combustible gas control requirements and constituted significant relaxations of the requirements. The proposed rule changes became effective on October 16, 2003. The ESBWR DCD was written to be consistent with these rule changes.

The applicant states in DCD Tier 2, Revision 9, Section 6.2.5.1 that 10 CFR 50.44(c)(2) establishes for future water-cooled reactor applicants and Licensees that “all containments must have an inerted atmosphere, or must limit hydrogen concentrations in containment during and following an accident...” The applicant then states, “The design of the ESBWR provides for an inerted containment and, as a result, no system to limit hydrogen concentration is required.”

The ESBWR containment inerting system can be used under postaccident conditions for containment atmosphere dilution to maintain the containment in an inerted condition by a controlled purge of the containment atmosphere with nitrogen to prevent reaching a combustible gas condition. Thus, the applicant did not propose a specification similar to BWR/4 STS 3.6.3.3 for the containment atmosphere dilution system for design-basis hydrogen control.

RAI 16.2-110 The staff asked the applicant to add a GTS to limit containment oxygen concentration to less than 4 percent by volume, based on BWR/4 STS 3.6.3.2. RAI 16.2-110 was being tracked as an open item in the SER with open items. In response, the applicant proposed establishing availability controls for containment oxygen concentration. In a follow-up question, the staff stated the following:

The regulatory limit proposed by the applicant, based on the future design certification rulemaking for ESBWR, will be too far removed from the day-to-day operation of a plant to provide sufficient control of and attention to the containment oxygen concentration limit. It adds little to the requirements already present in 10 CFR 50.44. Further, using the applicant’s suggested Availability Control also lacks sufficient regulatory force. The staff’s position is that a GTS limiting condition for operation must be established for an inerted containment to meet 10 CFR 50.36(c)(2)(ii)(D). The structure is the inerted containment. The NRC has determined that combustible gases produced by beyond design-basis accidents involving both fuel-cladding oxidation and core-concrete interaction would be risk-significant for plants with inerted containments, if not for the inerted containment atmosphere. It is essential to have a regulatory limit on containment oxygen concentration in each ESBWR plant license, meaning a GTS LCO. Provide a GTS of this type in DCD Chapter 16.

Section 6.2.5 of this report contains the staff’s evaluation of combustible gas control for the ESBWR design.

In response to RAI 16.2-110 S01, the applicant proposed establishing a GTS for containment oxygen concentration - GTS 3.6.1.8, “Containment Oxygen Concentration.” The proposed GTS is consistent with STS 3.6.3.2, “Primary Containment Oxygen Concentration,” in NUREG–1433. Therefore, the staff finds GTS 3.6.1.8 acceptable.

In response to RAI 16.2-110 S01, the applicant also proposed a new special operations GTS to allow suspension of LCO 3.6.1.8 during the initial 120 effective full power days (EFPD) of operation to avoid the personnel hazard of an oxygen deficient containment atmosphere during startup testing, which requires containment entries to inspect components following the performance of some tests. This special operations GTS is consistent with TS 3/4.10.5, “Oxygen Concentration,” of NUREG–0123, Revision 2, “Standard Technical Specifications General Electric Boiling Water Reactors,” issued in 1979. Therefore, the staff finds GTS 3.10.9, “Oxygen Concentration - Startup Test Program,” acceptable.

Based on the proposed GTS for containment oxygen concentration, RAI 16.2-110 is resolved.

RAI 16.2-45 The staff requested that the applicant further justify omitting GTS requirements for CIV instrumentation functions in Mode 5. RAI 16.2-45 was being tracked as an open item in the SER with open items. In response, the applicant discussed the CIV and other system isolation instrumentation functions in the BWR/6 STS that are required when the plant is in hot shutdown, cold shutdown, and refueling. The applicant determined that no CIV instrumentation functions were required in cold shutdown and refueling to limit fission product release during and after postulated DBAs for the ESBWR because the fuel-handling accident does not assume containment isolation. Based on the applicant's determination, the staff finds that the GTS do not need to require CIV instrumentation functions to be operable in Mode 5 or during movement of irradiated fuel.

However, the applicant did not justify excluding CIV operability during OPDRVs. Rather, the applicant stated that it had determined that the instrumentation function to close the RWCU/SDC system containment penetrations upon detection of a leak from the RWCU/SDC system is required in Modes 5 and 6 to isolate the RPV to minimize loss of RCS inventory for core protection. Accordingly, the applicant proposed to add TS requirements for this isolation function in GTS Section 3.4. However, in DCD Tier 2, Revision 3, Chapters 16 and 16B, the applicant revised the location for specifying the RWCU/SDC isolation function in Modes 5 and 6 to GTS 3.3.6.3, "Isolation Instrumentation," and 3.3.6.4, "Isolation Actuation." As discussed below in RAI 16.2-45 S02, the staff requested additional information regarding this change.

In RAI 16.2-45 S01, the staff requested that the applicant consider revising the GTS to require CIVs and associated instrumentation functions to be operable during OPDRVs and irradiated fuel movement for the purpose of defense in depth. In response, the applicant explained that the "condition of OPDRVs in the BWR/6 STS requires mitigative features that essentially ensure capability of establishing a secondary containment boundary." The staff concurred with this statement. In response, the applicant also stated the following:

For the ESBWR, NEDO-33201, "ESBWR Certification Probabilistic Risk Assessment," dated September 2006, Section 16, "Shutdown Risk," evaluates drain down of the reactor pressure vessel (RPV) or Loss of Coolant Accidents (LOCAs) during shutdown. This evaluation concludes that closure of both lower drywell hatches provides the appropriate mitigative response for the shutdown LOCA below top of active fuel (TAF) event initiators during Modes 5 and 6.

Based on this conclusion, the applicant proposed to provide an availability control "that will assure the ability to immediately close the lower drywell hatches during OPDRVs." In DCD Tier 2, Revision 4, Section 19A.8.4, the applicant identified the lower drywell hatches as important nonsafety equipment and recommended regulatory oversight of their capability for timely closure to isolate the lower drywell to provide a "boundary for recovering vessel level following a Shutdown LOCA below top of fuel event." Section 22.5.5 of this report lists the ability to close the drywell hatches during shutdown conditions as meeting RTNSS Criterion 3 described in SECY 94-084, which states the following:

Structure, system, or component functions relied upon under power-operating and shutdown conditions to meet the Commission's safety goal guidelines of a core damage frequency (CDF) of less than 1×10^{-4} per reactor year, and a large release frequency (LRF) of less than 1×10^{-6} per reactor year.

The applicant established an availability control for drywell hatches requiring the lower drywell personnel air lock and lower drywell equipment hatch to be available for closure in Modes 5

and 6. This applicability does not need to include “during OPDRVs” because the equipment hatches to the lower drywell would not be opened in other modes. See Section 22.5.9 of this report for an evaluation of availability controls. Based on this availability control, the staff determined that not requiring CIV operability during OPDRVs is acceptable.

In RAI 16.2-45 S02, the staff asked the applicant to explain how the GTS address operability and SRs for the automatic isolation valves for the RWCU/SDC system, associated with the following proposed isolation instrumentation functions in GTS 3.3.6.3 (the function numbers and titles, which changed subsequent to Supplement 2, are those given by DCD Revision 9):

- Function 1, “Reactor Vessel Water Level - Low, Level 2”
- Function 2, “Reactor Vessel Water Level - Low, Level 1”
- Function 5, “RWCU/SDC System Differential Mass Flow - High (Per Subsystem)”

The staff also asked for a similar explanation concerning the isolation actuation function in GTS 3.3.6.4 - Function 1, “RWCU/SDC System Isolation.”

In response, GEH stated that GTS 3.6.1.3 requires the automatic isolation valves for the RWCU/SDC system to be operable because they have a containment isolation function in Modes 1, 2, 3, and 4. Specifically, SR 3.6.1.3.7 requires periodic verification that each automatic CIV will actuate to its isolation position on a containment isolation signal. The bases for SR 3.6.1.3.7 state that the LSFTs in LCOs 3.3.6.2, 3.3.6.4, and 3.3.8.1 overlap this SR to provide complete testing of the safety function. The bases for SR 3.3.6.4.3, “Perform a [RWCU/SDC Isolation] system functional test,” state that “The LSFT in SR 3.3.6.4.1 and LCO 3.3.8.1 (for RWCU/SDC isolation valves) overlaps SR 3.3.6.4.3 to provide complete testing of the safety function.”

In Modes 5 and 6, the RWCU/SDC CIVs are not required to perform a containment isolation function, but are required to isolate the RWCU/SDC system from the RPV in case of a line break in the RWCU/SDC system.

In addition, the bases for GTS 3.3.6.4, isolation actuation Function 1, state the following:

The RWCU/SDC System Isolation actuation divisions receive input in Modes 1, 2, 3, and 4 from the following isolation instrumentation specified in GTS 3.3.6.3:

- Function 1, “Reactor Vessel Water Level - Low, Level 2”
- Function 2, “Reactor Vessel Water Level - Low, Level 1”
- Function 4, “Main Steam Tunnel Ambient Temperature - High”
- Function 5, “Reactor Water Cleanup/Shutdown Cooling System Differential Mass Flow - High (per RWCU/SDC subsystem)”

In MODES 5 and 6, the RWCU/SDC System Isolation actuation divisions only receive input from GTS 3.3.6.3 isolation instrumentation Function 1 and Function 5.

Based on the information provided in the applicant's responses, the bases for GTS 3.3.6.3, 3.3.6.4, 3.3.8.1, and 3.6.1.3 in DCD Revision 9, and the above conclusions about not requiring CIVs during movement of irradiated fuel or during OPDRVs, RAI 16.2-45 is resolved.

RAI 16.2-47 The staff asked the applicant to provide additional justification for the 24-month surveillance frequency of SR 3.6.1.6.3 to verify that each wetwell-to-drywell vacuum breaker fully opens at the specified minimum differential pressure. In response to RAI 16.2-47, the applicant stated it had previously addressed this question in response to RAI 3.9-1, by providing reference documents containing information regarding vacuum breaker testing in support of the SBWR design. Specifically, the applicant stated the following:

As stated in DCD, Tier 2, Subsection 6.2.1.1.5.3.2, the ESBWR vacuum breakers are not equipped with an air actuated cylinder. Testing for freedom of movement requires access to the vacuum breakers; therefore, this SR can only be performed with the plant in a shutdown condition. In addition to the changes in vacuum breaker configuration discussed in DCD Subsection 6.2.1.1.5.3.2, the reliability studies referenced by MFN 06-127 showed the ESBWR vacuum breakers to be highly reliable. Therefore, GE has determined that a 24-month Frequency is appropriate.

Based on the stated reasons, the 24-month frequency is acceptable, and RAI 16.2-47 is resolved.

RAI 16.2-48 The staff requested that the applicant provide an acceptable differential pressure value in place of the curly brackets in SR 3.6.1.6.3, "Verify each required vacuum breaker opens at $\{ \}$ kPaD." In DCD Revision 5, the applicant provided an acceptable maximum differential pressure value of 3.07 kPaD (0.445 psid) in SR 3.6.1.6.3, consistent with the vacuum breaker opening pressure in DCD Tier 2, Section 6.2.1.1.2, Table 6.2-1. Therefore, RAI 16.2-48 is resolved.

RAI 16.2-49 The staff requested that the applicant justify the omission of a surveillance to test wetwell-to-drywell vacuum breaker butterfly valves and their solenoid valves. In response, the applicant reiterated its commitment "to include the drywell-to-wetwell vacuum breaker proximity switch and downstream isolation valve testing in the GTS," which it made in response to RAI 16.0-1. The applicant met this commitment with SR 3.6.1.6.4, which requires the performance of a channel calibration, and SR 3.6.1.6.5, which requires the performance of a system functional test, for each vacuum breaker flow path isolation function on a 24-month frequency. Therefore, RAI 16.2-49 is resolved.

RAI 16.2-50 The staff asked that the applicant describe how it anticipates performing SR 3.6.3.1.4 to verify that the reactor building exfiltration rate is within limits and to justify the 60-month frequency. In response, the applicant indicated that the 60-month frequency was adequate to ensure that the leak rate assumptions remain valid because of "general building integrity inspections." However, the associated GTS bases for SR 3.6.3.1.4 state that the 60-month frequency is based on engineering judgment, but does not say why it is acceptable. The staff requested that the applicant provide clearer justification for the 60-month frequency in the GTS bases for SR 3.6.3.1.4.

In RAI 16.2-50 S01, the staff requested that the applicant respond to the original question to the extent permitted by currently available information, even though "construction-level-design details" are not currently available. The applicant's response referenced the response to related

RAI 15.4-26, which described the reactor building flow paths needing to be isolated and the method to be used to verify the reactor building leak rate. The staff verified that the applicant updated the DCD to reflect changes proposed in the response to RAI 15.4-26. See Section 15.4 of this report for the evaluation of RAI 15.4-26. However, neither response offered further justification for the 60-month frequency.

In RAI 16.2-50 S02, the staff requested that the applicant provide additional justification for the 60-month frequency or revise it to 24 months. In addition, the staff asked the applicant to revise the bases for this frequency to be consistent with the bases for the frequency for the secondary containment boundary integrity verification SRs, such as BWR/6 STS SR 3.6.4.1.5. In response, GEH stated it will revise the frequency for GTS SR 3.6.3.1.5 to 24 months and make conforming changes to the associated bases, consistent with the STS bases for STS SR 3.6.4.1.5. The staff reviewed the markup of the affected GTS pages, which had been provided in the response letter, and found them to be acceptable. The staff confirmed that DCD, Revision 9, included the changes shown in the markup. Therefore, RAI 16.2-50 is resolved.

RAI 16.0-3 The staff asked the applicant to list the STS generic changes (TSTF travelers) that it is proposing for the GTS, which are not included in STS Revision 3, including any proposed changes under review by the staff. The staff also requested that the applicant explain any deviations from these travelers. In response, the applicant listed unapproved TSTF-458-T, Revision 0, "Removing Restart of Shutdown Clock for Increasing Suppression Pool Temperature," as being incorporated in the GTS. The staff's evaluation of this TSTF follows.

TSTF-458-T makes the following changes to STS 3.6.2.1, "Suppression Pool Average Temperature," to remove a potential ambiguity between Actions D and E:

- Condition D applies when the suppression pool average temperature exceeds 43.3 degrees C (110 degrees F) regardless of how high the suppression pool average temperature rises, instead of just up to 48.9 degrees C (120 degrees F), so that regardless of any temperature increase above 48.9 degrees C (120 degrees F), the 36-hour completion time clock of Required Action D.3, to be in cold shutdown, will not reset.
- Required Action D.2 changes from "verify suppression pool average temperature $\leq 120^{\circ}\text{F}$ [48.9 $^{\circ}\text{C}$] every 30 minutes" to "determine suppression pool average temperature every 30 minutes," to ensure timely detection of temperature changes.
- For the condition of suppression pool average temperature above 48.9 degrees C (120 degrees F), Action E changes with the removal of Required Action E.2, to be in cold shutdown in 36 hours, which leaves only Required Action E.1 to depressurize the reactor vessel to less than 1.38 MPaG (200 psig) within 12 hours (i.e., to be in hot shutdown; 1.38 MPaG [200 psig] saturated steam corresponds to an RCS temperature of approximately 190.5 degrees C [375 degrees F]).

Resetting the shutdown completion time clock of Required Action D.3 when the suppression pool average temperature exceeds 48.9 degrees C (120 degrees F) is not the intended requirement. When the suppression pool average temperature exceeds and stays above 43.3 degrees C (110 degrees F), the intent of STS 3.6.2.1 Actions D and E, is to require placing the unit in cold shutdown in 36 hours, regardless of how high the temperature rises. The clarification of these ambiguous action requirements is consistent with this intent and is an administrative change. Therefore, TSTF-458-T is acceptable.

In RAI 16.0-3 S01, the staff noted that proposed ESBWR TS 3.6.2.1, “Suppression Pool Average Temperature,” differed significantly from TSTF-458-T in the following ways:

- Required Action D.2 still requires “verifying” instead of “determining” temperature.
- STS Required Action D.3, to be in cold shutdown within 36 hours of entering Condition D, is deleted.
- Required Action E.2, to be in cold shutdown within 36 hours of entering Condition E, is not deleted.
- Condition D applies when the suppression pool average temperature exceeds 48.9 degrees C (120 degrees F), instead of the STS value of 43.3 degrees C (110 degrees F), and Condition E applies when the suppression pool average temperature exceeds 54.4 degrees C (130 degrees F), instead of the STS value of 48.9 degrees C (120 degrees F).

In response, the applicant committed to change DCD Chapters 16 and 16B to incorporate without deviation TSTF-458-T, but to use the higher temperatures appropriate to the ESBWR suppression pool design. Staff review of the proposed pool temperature limits depended on the GEH response to RAI 6.2-159. The applicant provided additional information in response to RAI 6.2-159 to support the higher suppression pool temperatures for the ESBWR. Based on this information, the staff concluded that the higher suppression pool temperatures proposed for the ESBWR design are acceptable. The staff verified that the proposed changes had been incorporated into GTS 3.6.2.1 and bases. Therefore, this part of RAI 16.0-3 is resolved.

The ESBWR GTS for containment systems implement modified versions of the STS for containment systems. The staff finds that the GTS for containment systems have been constructed to be essentially equivalent to the STS for the containment cooling and isolation functions. For those cases in which STS for containment systems have not been included, ESBWR design differences provide sufficient justification for such omissions. Therefore, the staff finds the ESBWR GTS and bases for containment systems acceptable.

16.2.10 ESBWR GTS Section 3.7, “Plant Systems”

The ESBWR GTS for plant systems correspond to the STS as follows:

<u>STS</u>	<u>ESBWR TS</u>	<u>ESBWR TS TITLE (*STS TITLE)</u>
3.7.1*	None	(*Standby Service Water System and Ultimate Heat Sink (UHS))
3.7.2*	None	(*High Pressure Core Spray Service Water System)
3.7.1*	3.7.1	Isolation Condenser/Passive Containment Cooling System (IC/PCCS) Pools (*Standby Service Water System and Ultimate Heat Sink (UHS))
3.7.3*	3.7.2	CRHAVS (*Control Room Fresh Air System)
3.7.4*	None	(*Control Room Air Conditioning System)
3.7.5*	3.7.3	Main Condenser Offgas (*same)
3.7.6*	3.7.4	Main Turbine Bypass System (*same)
3.7.7*	3.7.5	Fuel Pool Water Level and Temperature (*Fuel Pool Water Level)
None	3.7.6	Selected Control Rod Run-In (SCRRI) and Select Rod Insert (SRI) Functions

The GTS contain no specification for the PSWS in conjunction with the ultimate heat sink (UHS) analogous to STS 3.7.1. The PSWS does not perform any safety-related function. There is no interface with any safety-related component. Omission of specifications for the PSWS in conjunction with the nonsafety UHS system (e.g., cooling tower) is acceptable because these systems do not perform safety-related functions and do not satisfy any of the criteria in 10 CFR 50.36(c)(2)(ii).

16.2.10.1 Plant Service Water System

The PSWS consists of two independent and 100-percent redundant trains that continuously circulate water through the RCCWS and turbine component cooling water system (TCCWS) heat exchangers. It has functions related to the RTNSS to provide post-72-hour cooling to the RCCWS and TCCWS. Section 22.5.9 of this report addresses these short-term availability controls. The PSWS is designed so that neither a single active nor single passive component failure results in a complete loss of nuclear island cooling and/or plant dependence on any safety-related system. This is achieved by redundant components, automatic valves, and piping cross-connects for increased reliability.

16.2.10.2 Isolation Condenser/Passive Containment Cooling System Pools

The water volume of the IC/PCCS pools provides the safety-related UHS function through evaporation. The ICS and the PCCS provide safety-related heat removal for design-basis events. The ICS and PCCS pools are safety related and contain sufficient water volume to act as the UHS, through evaporation, for a period of 72 hours after a DBA without replenishment; after that, operators must manually replenish the IC/PCCS pools using the fire water system, which is subject to short-term availability controls. LCOs 3.5.4, 3.5.5, 3.6.1.7, and 3.7.1 require the ICS, PCCS, and the IC/PCCS pools to be operable.

RAI 16.2-78 The staff requested that the applicant describe the surveillance (including IST) and action requirements that would apply to the valves in the makeup water transfer line from the fire protection water system and the offsite water supply sources to the FAPCS. The availability of these flow paths and water sources is necessary to extend the passive cooling by the IC and PCCS beyond the initial 72 hours following a design-basis event and to replenish any water lost through evaporation from the spent fuel pool. In response, the applicant stated that it had enhanced the makeup water capability by replacing the single isolation valve with two isolation valves in parallel in the design of the water supply line from the fire protection system to the FAPCS. The applicant also stated that it would apply short-term availability controls under RTNSS, and these controls would include appropriate testing requirements to ensure the availability of makeup water for the IC/PCCS pools and the spent fuel pools. The staff verified that the ACM contains the proposed availability controls, and concluded that they are acceptable. Therefore, RAI 16.2-78 is resolved.

RAI 16.2-182 The staff requested that GEH revise the actions and surveillances of GTS 3.7.1 to address the following items. The GEH response is described with each item.

- The staff asked GEH whether the IC/PCCS pool temperature could be kept within its limit of 43.3 degrees C (110 degrees F), with drywell temperature at its limit of 65.6 degrees C (150 degrees F), because the IC/PCCS pools are located above and outside the containment boundary, directly above the drywell top slab. GEH stated that the drywell air space temperature is not expected to challenge the ability of the FAPCS to maintain the

IC/PCCS pool temperature because the drywell air space must transfer heat through the floor of the IC/PCCS pool. The staff finds this response acceptable.

- The staff asked GEH to clarify the bases description of the connections between the IC/PCCS subcompartment pools and inner expansion pools. GEH clarified the bases upon which the following summary is based. Each IC/PCCS subcompartment pool is connected to one of two inner expansion pools by locked open manual valves, which are verified to be open to support operability of each ICS train (SRs 3.5.4.4 and 3.5.5.4) and each PCCS condenser (SR 3.6.1.7.2). Each inner expansion pool consists of three connected partitions, with a normally locked open manual valve in each connection. Each inner expansion pool is connected to the common (i.e., single) equipment pool by two piping connections. One connection to each expansion pool contains a squib-actuated pool cross-connect valve. The other connection to each expansion pool contains one fail-as-is double-acting pneumatic piston cross-connect valve. The pool cross-connect valves open automatically on inner expansion pool low level. Four level instrument channels monitor each IC/PCCS inner expansion pool and initiate an opening signal to all four of the expansion pool-to-equipment pool cross-connect valves on low level in either inner expansion pool. Opening one pool cross-connect valve from the equipment pool to each inner expansion pool provides the required makeup from the equipment pool to the inner expansion pools. Each inner expansion pool-to-equipment pool connection also includes a manually operated valve, which is normally locked open. The manual isolation valve on each of the four inner expansion pool-to-equipment pool lines and between each of the inner expansion pool partitions is verified to be locked open (SR 3.7.1.8) to support operability of the IC/PCCS pools. Operability of the IC/PCCS pools also requires that the reactor well gate not be installed (SR 3.7.1.9). By connecting the equipment pool and reactor well pool to the inner expansion pools, the volume of water available to the ICS and PCCS subcompartments is sufficient to support DHR for 72 hours without operator action or the need to replenish the water in the inner expansion pools. The staff concluded that Revision 6 of the bases for GTS 3.7.1 provides a clear description of connections between the IC/PCCS subcompartment pools and inner expansion pools and between the inner expansion pools and the equipment pool and the reactor well.
- The staff asked GEH how SR 3.7.1.4, "Verify average water temperature in IC/PCCS pools is $\leq 43.3^{\circ}\text{C}$ (110°F)," can be met if one or more IC/PCCS pools are not available or isolated from the expansion pool or equipment pool, because only the temperature of the water in each of the available pools should be used to determine the average temperature. The applicant revised the SR to indicate that the average water temperature is determined by the volume and temperature of the water in the "available" IC/PCCS pools. This is acceptable.
- The staff asked GEH to clarify that SR 3.7.1.6, which requires verification of the continuity of DPS initiator and two safety-related initiators, applies to each of the four expansion pool-to-equipment pool valves (one valve in each of the two connection lines on each expansion pool). GEH stated that the presentation in the SR and bases needed no clarification. This is acceptable because it matches the level of detail typically found in the STS for similar SRs.
- The staff requested that GEH revise the scope of Actions C and D by removing conditions corresponding to a loss of capability to open at least one connection between each expansion pool and the equipment pool (i.e., makeup available to both expansion pools through equipment pool connections). GEH deleted Action C, which had proposed allowing 7 days for the condition of just one operable connection to one expansion pool. The

applicant relabeled Action D as Action C and retained the allowance of 8 hours to restore IC/PCCS pools to operable status when an IC/PCCS pool is inoperable for reasons other than Condition A, B, or C. GEH stated that this completion time was acceptable because (1) it was consistent with Action C of the AP1000 generic TS 3.6.6, "Passive Containment Cooling System (PCCS)," which specifies 8 hours to restore PCCS water storage tank parameters (temperature and volume) to within limits, (2) even with all equipment pool connections isolated, the IC/PCCS subcompartment and expansion pools still provide heat removal capability, and (3) there are alternate methods of providing makeup to the IC/PCCS pools (e.g., the bases state that the FAPCS includes flow paths for postaccident makeup water transfer from the fire protection system and off-site water supply sources to the IC/PCCS pools). The revised action requirements are therefore acceptable.

The staff verified that the applicant incorporated the changes proposed to GTS 3.7.1 in DCD Revision 6. Therefore, RAI 16.2-182 is resolved.

RAI 16.2-189 In DCD Revision 5, GTS SR 3.7.1.8 verifies actuation of each of the four IC/PCCS pool inner expansion pool-to-equipment pool cross-connect valves on an actual or simulated automatic initiation signal. The bases of SR 3.7.1.8 state that this SR overlaps the LSFT required by GTS SR 3.3.8.1.4 for DPS Function 5.a, "IC/PCCS Pool Expansion Pool to Equipment Pool Cross-Connect - Actuation, IC/PCC System Pool Level - Low," to provide complete testing of the assumed safety function. However, the GTS included no LCO or LSFT SR for the safety-related actuation logic function associated with the safety-related initiators on the cross-connect valves. Also, SR 3.5.4.5, which overlaps the LSFT of SR 3.3.5.4.1, does not appear to address the safety-related initiators for opening the cross-connect valves. Consequently, the staff asked GEH to revise the GTS as described in the following discussions. GEH's response is described in each discussion.

- The staff asked GEH to add an LCO to explicitly require operability of (1) the safety-related IC/PCCS inner expansion pool level - low instrumentation function channels, and (2) the safety-related actuation logic function divisions that actuate to open the IC/PCCS pool inner expansion pool-to-equipment pool cross-connect valves on low level in at least one inner expansion pool.

In response, GEH stated it will revise GTS LCO 3.7.1 and the associated bases to explicitly require operability of the instrumentation channels, actuation logic divisions, and valve initiators associated with the IC/PCCS expansion pool-to-equipment pool cross-connect function. GEH also stated it will add SR 3.7.1.1 and SR 3.7.1.7 and associated bases to require performance of channel checks and channel functional tests of the IC/PCCS expansion pool level instrumentation. Along with the revised LCO and SRs, GEH also stated it will revise DCD Tier 2, Section 7.4.4.3 and the bases for GTS 3.3.8.1, "Diverse Protection System (DPS)," to clarify the number of initiators on each of the cross-connect valves; e.g., "Each valve has four initiators (three divisional initiators and one DPS initiator)."

- The staff asked GEH to revise the GTS and bases by adding (1) a LSFT SR for these safety-related actuation logic function divisions, (2) appropriate action requirements for both the inner expansion pool level instrument channels and expansion pool-to-equipment pool cross-connect actuation divisions, and (3) appropriate bases for the LCO, actions, and SRs, including the overlap of the LSFT with tests of the valve initiators on an actual or simulated automatic initiation signal.

In response, GEH stated it will add SR 3.7.1.12 and associated bases to require a LSFT of the logic associated with the IC/PCCS expansion pool-to-equipment pool cross-connect function. The LSFT will test the safety-related logic associated with the safety-related valve initiators.

GEH also stated it will add Required Action D.1 and Required Action E.1 to GTS 3.7.1 and bases to address the inoperability of a required instrument channel or actuation logic division, respectively. GTS 3.7.1 will specify a Completion Time of 20 hours for Required Actions D.1 and E.1 to restore the required instrument channel or actuation logic division to operable status. This Completion Time is consistent with the GTS Section 3.3 required action completion times because it includes (1) the typical 12-hour allowance to restore an ESBWR instrumentation channel/actuation division to operable status, followed by immediately declaring the supported component inoperable; and (2) the typical 8-hour allowance to restore the affected IC/PCCS pool to operable status. Failing that, GTS 3.7.1 (renumbered) Action G will require a unit shutdown.

Finally, GEH stated it will revise the bases for SR 3.7.1.10 (previously SR 3.7.1.8) to state that SR 3.7.1.10, which verifies actuation of each of the four IC/PCCS pool inner expansion pool-to-equipment pool cross-connect valves on an actual or simulated automatic initiation signal, overlaps the LSFT of SR 3.7.1.12.

- GEH also confirmed the staff's observation about SR 3.5.4.5 by stating that "SR 3.5.4.5 does not test any feature of the IC/PCCS expansion pool-to-equipment pool cross-connect function. The cross-connect function safety-related initiators are fully tested via existing SR 3.7.1.10 (previously SR 3.7.1.8), which overlaps with newly created SR 3.7.1.12."

The staff reviewed the markup of the DCD pages that were affected by the above described changes and included in the response letter, and found them to be acceptable. These changes result in acceptable GTS operability, action, and surveillance requirements for the IC/PCCS expansion pool-to-equipment pool cross-connect instrumentation and actuation functions. Therefore, RAI 16.2-189 is resolved.

GTS 3.7.1 requires the IC/PCCS pools to be operable and provides appropriate action and surveillance requirements. Therefore, GTS 3.7.1 and bases are acceptable.

16.2.10.3 Control Room Habitability Area Heating, Ventilation, and Air Conditioning Subsystem

CRHAVS is designed to automatically provide safety-related ventilation and radiation protection to keep the CRHA habitable following a design-basis event. Each redundant train is electrically independent and capable of performing the specified safety function. GTS LCO 3.7.2 requires two CRHAVS trains to be operable in Modes 1, 2, 3, and 4, and during OPDRVs. To automatically maintain a safe environment in the CRHA following a design-basis event, the CRHAVS relies on (1) ventilation dampers to isolate normal nonfiltered air intakes and exhaust ducts, (2) emergency filtration units and supply fans to supply and filter outside air, which may contain radioactivity, to the CRHA, and (3) the thermal design of the CRHA boundary, along with the CRHAVS filtered air supply, to maintain CRHA air temperature within acceptable limits.

The CRHAVS does not rely on air conditioning units for temperature control following isolation of CRHA nonfiltered air intakes and exhaust ducts as does the BWR/6 STS CR fresh air and control room air conditioning systems (CRACS). The STS require an operable CRACS. The

bases for GTS 3.7.2 state that, following a DBA, the CRHAVS air-handling units, which provide air conditioning, are assumed to initially operate with power from nonsafety-related uninterruptible ac sources, for up to 2 hours, to remove heat from nonsafety loads within the CRHA to maintain temperature less than or equal to 25.6 degrees C (78 degrees F) (this was changed to 23.3 degrees C [74 degrees F] in DCD Revision 7). After 2 hours, these nonsafety loads are tripped and passive heat transfer from the CRHA to the CRHA boundary, which functions as a passive heat sink, limits the CRHA temperature increase to 10.6 degrees C (19 degrees F) until ac power is restored no later than 72 hours after the start of the event.

RAI 16.0-5 S01 and S02; RAI 16.2-118; and RAI 16.2-183 The staff requested additional information to either justify the proposed GTS 3.7.2 LCO, action, and surveillance requirements and associated bases, for the CRHAVS or to revise these requirements to ensure that acceptable temperatures are maintained in the CRHA following a design-basis event. The applicant responded to the staff's questions as follows.

In RAI 16.0-5 S01, the staff asked GEH to justify its decision not to include an LCO for the CRHA filtered ventilation and cooling subsystem and a programmatic specification for ventilation filter testing. GEH stated in response that the intent of the application of the 10 CFR 50.36(c)(2)(ii) LCO criteria is limited to the protective and mitigative features that are credited in the primary success path during the first 72 hours following the start of a postulated event. Referring to its response to RAI 16.0-1, GEH determined that the CRHA filtered ventilation and cooling subsystem did not meet the LCO criteria. At that time, the emergency bottled air system (EBAS) was the safety-related CRHA habitability system in the ESBWR design, which was intended to meet General Design Criterion 19, "Control room" (see Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities"). GEH indicated that it had not completed its assessment of nonsafety systems for regulatory treatment in the form of short-term availability controls, which would include consideration of the CRHA filtered ventilation and cooling subsystem. GEH requested that staff questions about the RTNSS be addressed in response to the NRC review of DCD Tier 2, Chapter 19A.

In RAI 16.0-5 S02, following the design change to replace the EBAS with the CRHAVS, the staff asked the applicant to establish an ITAAC to demonstrate the claimed postaccident temperature behavior of the CRHA and passive heat sink (i.e., the CRHA temperature increase limited to 8.3 degrees C (15 degrees F) (this was changed to 10.6 degrees C [19 degrees F] in DCD Revision 7) until ac power is restored no later than 72 hours after the start of the event). The staff also questioned the 72-hour allowance of GTS 3.7.2, Action A, to restore CRHA temperature to less than or equal to 25.6 degrees C (78 degrees F) (this was changed to 23.2 degrees C [74 degrees F] in DCD Revision 7). RAI 16.0-5 was being tracked as an open item in the SER with open items. In response, GEH pointed out an ITAAC (see DCD Tier 1, Revision 4, Section 2.16.2.2, Item 4, and Table 2.16.2-4) related to verification of the CRHA passive cooling capability. GEH stated the following:

ITAAC ensure that the Control Room Habitability Area (CRHA) temperature increase will be < 8.3 °C (15 °F) during the 72 hours following loss of normal cooling by passively dissipating heat to CRHA heat sinks. This ITAAC confirms that the non-safety-related air conditioning units are not required to limit the increase in CRHA temperature consistent with design commitments in DCD, Tier 2, Section 9.4.1 and DCD, Tier 2, Section 6.4.

In DCD Tier 1, Revision 7, Table 2.16.2-4, GEH revised ITAAC item 4 as a result of the resolution of RAI 6.2-24 S01. The staff's evaluation of the response to RAI 6.2-24 S01 and the revised ITAAC are discussed in Section 6.2.1.2 of this report.

GEH also made changes to the DCD "to ensure that the DCD fully describes the CRHA heat sink and that Technical Specification Surveillance Requirements verify that CRHA heat sink analysis initial conditions and assumptions are met." The applicant incorporated the following changes in DCD Revision 5, as revised by DCD Revisions 6 and 7:

- DCD Tier 2, Sections 6.4 and 9.4.1 were revised to more completely describe the CRHA heat sinks and temperature limits assumed in the CRHA temperature analysis.
- GTS 3.7.2, "CRHAVS," and bases were revised to expand the requirements of SR 3.7.2.1 to define the CRHA heat sinks and establish acceptance criteria consistent with the changes to DCD Tier 2, Sections 6.4 and 9.4.1. This SR requires verifying once every 24 hours that the average temperature for each CRHA heat sink is within established design limits (DCD Tier 1, Revision 7. Section 3H).
- Actions of GTS 3.7.2 were revised to limit the duration of a heat sink temperature excursion when air temperatures in the CRHA or adjacent spaces are not being maintained within SR 3.7.2.1 limits. Specifically, GEH reduced the completion time for restoration of a CRHA heat sink temperature to within the SR 3.7.2.1 limit from 72 hours to 24 hours, as long as the average air temperature of the area associated with the heat sink is restored to below the specified value within 8 hours. The applicant justified these changes by stating, "These Actions will ensure that CRHA heat sink temperatures are restored, or reactor shutdown initiated, before there is a substantial degradation of the CRHA heat sinks."

In RAI 16.2-118, the staff asked GEH to address several items about the CRHA heat sink requirements of GTS 3.7.2 in DCD Revision 3, including (1) correction of a typographical error in the bases, (2) additional justification for the 72-hour completion time for Required Action A.1 to restore CRHA temperature to within the limit, and (3) recommendation to require an operable air handling unit (AHU) for the associated CRHAVS subsystem train to be operable, with appropriate action and surveillance requirements for the AHUs with supporting auxiliary cooling units, which provide active cooling of the CRHA. RAI 16.2-118 was being tracked as an open item in the SER with open items. In response, GEH corrected the typographical error by revising the fourth sentence of the "ASA" section of the bases for GTS 3.7.2 to state, "No single active or passive failure will cause the loss of outside air to the CRHA." This clarification corrected the error so that the bases are consistent with the DCD Tier 2, Section 6.4 description of the CRHAVS subsystem. Therefore it is acceptable. In response to RAI 16.2-118, GEH also referred to its response to RAI 16.0-5 S02, regarding the reduced completion time of 24 hours to restore a CRHA heat sink temperature to within limit; e.g., for the main control room, restore heat sink temperature to less than or equal to 25.6 degrees C (78 degrees F) (this was changed to 23.2 degrees C [74 degrees F] in DCD Revision 7); and its decision not to include an LCO for CRHA air conditioning. The response to RAI 16.2-118 provided no additional justification for not specifying the AHUs with supporting auxiliary cooling units in LCO 3.7.2 beyond that given by its response to RAI 16.0-5 S02.

In RAI 16.2-183, the staff requested that the applicant respond to the following items regarding GTS 3.7.2 in DCD Revision 5. Each item describes the associated GEH response. The staff's conclusions are provided with each item.

- The staff asked GEH to add action and surveillance requirements for CRHA air temperature to be less than or equal to the limit; e.g., 25.6 degrees C (78 degrees F) (this was changed to 23.2 degrees C [74 degrees F] in DCD Revision 7) at all measured locations in the main control room (i.e., no areas above this limit). GEH replied that the requested action and surveillance requirements are not necessary because monitoring the heat sink “average” air temperature ensures that the bulk heat sink temperatures are within limits consistent with the analysis assumptions. For clarification, GEH revised Condition A to state, “One or more CRHA heat sink(s) with average temperature not within limit.” The staff concludes that the response to this item is acceptable because the design of the CRHAVS subsystem (described in DCD Sections 6.4 and 9.4.1) ensures adequate mixing of air in the CRHA so that during normal operation the average air temperature associated with each CRHA heat sink will be representative of the bulk heat sink temperature.
- The staff questioned the adequacy of GTS 3.7.2, Required Action A.1, which requires verifying every 8 hours that each CRHA average heat sink temperature is less than or equal to 4.4 degrees C (8.0 degrees F) above the specified limit of 25.6 degrees C (78 degrees F) (this was changed to 23.2 degrees C [74 degrees F] in DCD Revision 7). The staff asked that GEH provide additional information to demonstrate that acceptable CRHA air temperatures will be maintained should a design-basis event occur with the average temperatures for all CRHA heat sinks at 30 degrees C (86 degrees F). In response, GEH revised Required Action A.1 to require that each CRHA heat sink average air temperature be restored to within limits within 8 hours. The 8-hour completion time is intended to allow the operator time to evaluate and repair any discovered inoperable SSCs related to the high CRHA air temperature while minimizing risk. GEH stated that restoring the CRHA heat sink average air temperatures to within limits within 8 hours controls the temperature excursion of the CRHA heat sink structure because the temperature response of the CRHA heat sink area materials is slower than the response of the average air temperature on increasing temperature (i.e., on a loss of normal cooling). The bases state that restoring the CRHA heat sink to within limits within 24 hours (Required Action A.2) can be performed by either administrative evaluation, considering the length of time and extent of the average air temperature excursion and the known thermodynamic properties of the structural materials, or by direct measurement of the temperature of the structural materials. Based on this rationale, the staff finds that Action A is acceptable.
- The staff asked GEH to describe how CRHA heat sink temperatures are measured. GEH stated that details of how the heat sink structure temperatures and heat sink average air temperatures are measured are procedural details beyond the scope of the DCD and the GTS bases. The staff recognizes that procedural details for measuring heat sink temperature may not be appropriate for inclusion in the DCD or GTS bases, but asked the question to better understand how GEH envisions plant operation using passive cooling in the CRHA for 72 hours after an event. Monitoring heat sink capacity by monitoring average air temperature provides a rapid conservative indication of degradation of heat sink capacity. Room air temperature responds to ventilation changes more quickly than the materials in the heat sink (notably concrete). Therefore, this approach is conservative. The staff finds the response to this item acceptable because in the event of a loss of normal cooling in the CRHA and a rise in temperature above the limit, GTS 3.7.2 requires restoring air temperature to within the limit within a short time of 8 hours and likely before significant temperature changes can occur in the passive heat sink itself.
- The staff asked GEH to (1) explicitly state in SR 3.7.2.1 that Table B 3.7.2-1 identifies the established CRHA heat sink design temperatures and (2) revise the bases to reference the

location of these design temperatures in the DCD. GEH revised the bases for SR 3.7.2.1 to provide the location of the design limits by adding "(Ref. 4)," which is DCD Section 3H. The staff finds the response to this item acceptable because it is consistent with the STS conventions for writing SRs and because the bases now include a needed reference to the DCD.

- The staff requested that GEH clarify the ventilation damper alignment requirements for an operable CRHAVS train. GEH revised the LCO section of the bases for GTS 3.7.2 to clarify that, during normal operation, with the EFUs not in operation, the boundary isolation dampers associated with each EFU train are closed. During operation of an EFU fan, only the isolation dampers associated with the running EFU fan are open. The isolation dampers associated with the nonrunning EFU fans remain closed. The staff finds that the change to the bases provides the requested clarification. Therefore, the response to this item acceptable.

As described in the preceding evaluation of RAIs 16.0-5, 16.2-118, and 16.2-183, the staff finds the changes that the applicant made to GTS 3.7.2 and its bases to be acceptable. Therefore, RAIs 16.0-5, 16.2-118, and 16.2-183 are resolved.

RAI 16.2-54 The staff requested that the applicant adopt TSTF-448-A. In DCD Revision 3, the applicant changed the plant design to make CR ventilation safety related and accordingly added GTS 3.3.7.1, 3.3.7.2, and 3.7.2 for the CRHA instrumentation, actuation, and HVAC, respectively. The applicant also added GTS 5.5.13, "Ventilation Filter Testing Program (VFTP)," for the CRHAVS EFUs. The staff verified that the applicant had proposed GTS 3.7.2 and its bases and GTS 5.5.12, "CRHA Boundary Program," in accordance with the STS changes stipulated in TSTF-448-A, with no significant deviations. Therefore, RAI 16.2-54 is resolved.

Based on the above evaluation and RAI resolutions, the staff concludes that GTS 3.7.2 and bases are acceptable.

16.2.10.4 Main Condenser Offgas and Spent Fuel Pool Water Level and Temperature

GTS 3.7.3 for main condenser offgas and GTS 3.7.5 for spent fuel pool water level are essentially the same as the corresponding STS 3.7.5 and 3.7.7, respectively, and are therefore acceptable. See Section 16.2.12 of this report under the discussion of RAI 16.2-76 regarding the addition of a fuel pool temperature limit to GTS 3.7.5.

16.2.10.5 Main Turbine Bypass System

GTS 3.7.4 for the main turbine bypass system is essentially the same as the corresponding STS 3.7.6. The main turbine bypass system satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) because it is assumed to function as part of the primary success path during transient events that could increase reactor pressure, as described in DCD Tier 2, Revision 9, Section 15.2.2. However, neither the STS nor the GTS include explicit requirements for instrumentation sensors and logic that support the steam bypass function of the SB&PC system.

DCD Tier 2, Revision 9, Section 7.7.5.2.4 states that the "SB&PC system has no safety setpoints because it is not a safety-related system. Actual operational setpoints are determined during startup testing....The steam bypass function controls reactor pressure by responding to the bypass flow demand signal. It modulates the regulating bypass valves, which are

automatically operated. This control mode is assumed...during plant load rejection and turbine/generator trips.”

DCD Tier 2, Revision 9, Section 7.7.5, describes the SB&PC system, but does not discuss response time testing for the turbine bypass system. However, SR 3.7.4.3 specifies response time testing. GTS Section 1.1 provides the following definition of “turbine bypass system response time,” which is identical to that of the STS:

The TURBINE BYPASS SYSTEM RESPONSE TIME consists of two components:

- a. The time for initial movement of the main turbine stop valve or control valve until 80% of the turbine bypass capacity is established; and
- b. The time for initial movement of the main turbine stop valve or control valve until initial movement of the turbine bypass valve (TBV).

The response time may be measured by means of any series of sequential, overlapping, or total steps such that the entire response time is measured.

The bases for SR 3.7.4.3 states that the response time testing for the main turbine bypass system ensures that the response time complies with the assumptions of the “appropriate safety analysis.” In DCD Revision 6, the applicant revised the bases for SR 3.7.4.3 by adding the sentence, “The response time limits are specified in Reference 4.” The applicant revised the “References” section of the bases to include Reference 4, which is “Chapter 15, Table 15.2-1, ‘Input Parameters, Initial Conditions and Assumptions Used in AOO and Infrequent Event Analyses.’” This table contains the turbine bypass system response time values assumed in the accident analysis. The two components of the response time are listed as follows:

- “Total Delay Time from TSV or TCV to 80% of Total Bypass Valve Capacity, 0.17 seconds.”
- “Total Delay Time from TSV or TCV to the start of bypass valve Main Disc Motion, 0.02 seconds.”

The 24-month frequency for the turbine bypass system response time testing is consistent with the STS. Therefore, the staff finds SR 3.7.4.3 and its bases acceptable.

RAI 16.2-53 The staff asked the applicant to specify a 31-day frequency for the surveillance to cycle the turbine bypass valve and describe in the bases the conditions for relaxing this frequency from 31 to 92 days, for optional use by a COL applicant. In response, the applicant committed to revise the surveillance frequency to 31 days in GTS SR 3.7.4.1 and to describe the option to extend the frequency to 92 days in the GTS bases. DCD Revision 3 incorporated these changes. (DCD Revision 5 moved the frequency option discussion from the bases for SR 3.7.4.1 to DCD Table 16.0-1-A as a reviewer’s note for COL Item 3.7.4-2.) Therefore, RAI 16.2-53 is resolved.

Based upon the above, GTS 3.7.4 and bases are acceptable.

16.2.10.6 Selected Control Rod Run-In and Select Rod Insert Functions

The applicant proposed GTS 3.7.6, "Selected Control Rod Run-In (SCRRI) and Select Rod Insert (SRI) Functions," to specify operability of the SCRRI function and the SRI function. The bases state that the SCRRI and SRI functions are required to be operable to limit the decrease in MCPR to within acceptable limits such that the FCISL is not exceeded during events that could result in a decrease in core coolant temperature or an increase in reactor pressure and cause a rapid increase in core reactivity. These events are loss of feedwater heating, generator load rejection with turbine bypass, and turbine trip with turbine bypass. The SCRRI function provides for electrical insertion of selected control rods using the FMCRD. The SRI function provides for hydraulic scram insertion of selected control rods. This specification addresses the operability and SRs for the following:

- SCRRI/SRI signal from the DPS to the RC&IS
- SCRRI function logic in the RC&IS
- SCRRI/SRI signal from the automated thermal limit monitor control rod block instrumentation function to the RC&IS
- FMCRD induction motor controller logic and emergency rod insertion panels
- SRI function logic in the DPS
- Automatic SRI command signals to the scram timing test panel from the DPS and hard-wired turbine trip and load reject signals from the turbine control system
- Control rods associated with the SCRRI and SRI functions
- Electrical power to each FMCRD associated with the SCRRI function
- HCU solenoid return line switches for SRI function selected control rods
- Loss-of-feedwater-heating instrumentation channels

The actions allow just 2 hours to restore the SCRRI and SRI functions to operable status; otherwise, the unit must be brought to below 25-percent RTP within the next 4 hours. The 2-hour completion time is reasonable because it provides an appropriate length of time to repair the component causing the SCRRI or SRI function to be inoperable and there is a low probability of an event occurring during this period requiring the SCRRI and SRI functions. The 4-hour completion time is reasonable based on operating experience and allows sufficient time to reach the required unit condition from full-power conditions in an orderly manner and without challenging unit systems.

The staff finds GTS 3.7.6 and associated bases to be consistent with STS style conventions. It is also technically consistent with the ESBWR design. Therefore GTS 3.7.6 and bases are acceptable.

Section 3.7 of the GTS implements modified versions of the STS for plant systems. The staff finds that the GTS for plant systems are essentially equivalent to the STS for plant systems. For those cases in which the GTS do not include STS for plant systems, ESBWR design

differences provide sufficient justification for such omissions. Therefore, the staff finds that the GTS and bases for plant systems are acceptable.

16.2.11 ESBWR GTS Section 3.8, "Electrical Power Systems"

During the first 72 hours following the occurrence of a design-basis event, the ESBWR design relies only on dc electrical power sources (dc sources) for mitigating accident consequences and achieving a safe-shutdown condition of at least hot shutdown, Mode 3, or stable shutdown, Mode 4. (The definition of safe shutdown in DCD Tier 1, Revision 9, Section 1.2.1, includes the operational conditions of hot shutdown, stable shutdown, and cold shutdown.) Consequently, the applicant did not propose a GTS for ac sources corresponding to STS 3.8.1, "AC Sources - Operating," STS 3.8.2, "AC Sources - Shutdown," and STS 3.8.3, "Diesel Fuel Oil, Lube Oil, and Starting Air." The ESBWR design designates ac sources and associated ac electrical power distribution circuits (ac distribution) as nonsafety-related systems. However, after the initial 72-hour period, the design does require the availability of an ac source for maintaining a safe-shutdown condition. In addition, placing the plant in cold shutdown, Mode 5, is not possible without the availability of an ac source. Because an ac source is necessary for maintaining the plant in a safe-shutdown condition beyond 72 hours, the onsite ac sources (standby and ancillary diesel generators), and associated ac electrical power distribution circuits (ac distribution) are important from an RTNSS perspective and should be included in short-term availability controls. Section 22.5.9 of this report addresses the availability controls for onsite ac sources.

The dc sources supply emergency power to associated safety-related inverters, which convert 250-V dc power to 120-V ac power and provide uninterruptible 120-V ac power during all modes of operation. Uninterruptible 120-V ac power supplies all safety-related loads, including the safety-related DCIS and the control power for safety-related systems. The dc sources are designed to have sufficient capacity, independence, redundancy, and testing capability to perform their safety functions when any three of the four divisions are available, assuming a single failure of one of the three required divisions.

Each of the two safety-related inverters in each division receives power from an associated rectifier, or battery and battery charger. Both the battery charger and the rectifier are supplied with 480-V ac power by the associated division's isolation power center (IPC) bus. The battery charger and rectifier both convert 480-V ac power to 250-V dc power. If the battery charger and rectifier both lose ac power from the IPC bus, the associated safety-related 250-V battery will automatically supply the inverter by means of the 250-V dc bus. The output diodes for battery chargers and safety-related rectifiers isolate the output of each required battery from an associated 480 V ac IPC bus that is de-energized or has degraded voltage.

The ESBWR GTS for electrical power systems correspond to STS for electrical power systems as follows:

<u>STS</u>	<u>ESBWR TS</u>	<u>ESBWR TS TITLE (*STS TITLE)</u>
3.8.4*	3.8.1	DC Sources - Operating (*same)
3.8.5*	3.8.2	DC Sources - Shutdown (*same)
3.8.6*	3.8.3	Battery Parameters (*same)
3.8.7*	3.8.4	Inverters - Operating (*same)
3.8.8*	3.8.5	Inverters - Shutdown (*same)

<u>STS</u>	<u>ESBWR TS</u>	<u>ESBWR TS TITLE (*STS TITLE)</u>
3.8.9*	3.8.6	Distribution Systems - Operating (*same)
3.8.10*	3.8.7	Distribution Systems - Shutdown (*same)

GTS 3.8.1, which is applicable in Modes 1, 2, 3, and 4, requires dc sources to be operable to support the three divisions of dc electrical power distribution and the three divisions of uninterruptible ac electrical power distribution required by GTS LCO 3.8.6. GTS LCO 3.8.1 and LCO 3.8.6 are acceptable because three operable divisions of the dc electrical power distribution and three operable divisions of the uninterruptible ac electrical power distribution represent the lowest functional capability of the electrical power distribution system required for safe operation of the facility, assuming a design-basis event with a loss of all offsite and onsite ac sources and a single failure that results in the loss of one of the three electrical power distribution divisions. An operable division requires two operable dc sources. An operable dc source requires a 250-V battery, an associated battery charger, and all associated control equipment and interconnecting cable. The staff has concluded that the actions of GTS 3.8.1 and 3.8.6 are acceptable, as described below in the evaluation of RAI 16.2-82. The SRs are consistent with those in STS 3.8.4 and 3.8.9. Since the LCO, action, and SRs of GTS 3.8.1 are consistent with the STS and the ESBWR design, GTS 3.8.1 and 3.8.6, and the respective bases are acceptable.

GTS 3.8.2, which is applicable in Modes 5 and 6, requires dc sources to be operable to support the divisions of dc electrical power distribution and divisions of uninterruptible ac electrical power distribution required by LCO 3.8.7. GTS LCO 3.8.2 and LCO 3.8.7 are acceptable because they will ensure the availability of sufficient 250-V dc power sources and portions of the dc electrical power distribution and the uninterruptible ac electrical power distribution to operate the unit safely and to mitigate the consequences of postulated events during shutdown (e.g., inadvertent reactor vessel draindown). The fuel-handling accident analysis (DCD Tier 2, Revision 9, Section 15.4.1) does not credit the mitigation function provided by the CRHAVS charcoal filters. CR ventilation is assumed to operate in normal operation mode for the duration of the event. GTS 3.8.2 and 3.8.7 omit the applicability condition of “during movement of recently irradiated fuel” and the required action to immediately “suspend movement of recently irradiated fuel assemblies in the containment” when one or more required dc sources are inoperable, or one or more required electrical power distribution divisions are inoperable, respectively. The staff concludes that the actions of GTS 3.8.2 and 3.8.7 are acceptable as described below in the evaluation of RAI 16.2-82. The staff also concludes that the LCO, action, and surveillance requirements of GTS 3.8.2 and 3.8.7 are consistent with STS 3.8.5 and 3.8.10. Since the LCO, action, and surveillance requirements of GTS 3.8.2 and 3.8.7 are consistent with the STS requirements and the ESBWR design, GTS 3.8.2 and 3.8.7, and bases are acceptable.

Staff review of GTS 3.8.3, “Battery Parameters,” focused on differences associated with the proposed use of the VRLA battery type and resulted in the RAIs discussed below. These issues were resolved; however, when GEH changed to the VLA battery type, the applicant adopted action and surveillance requirements consistent with the STS and IEEE Standard 450-2002. Since the LCO, action, and surveillance requirements of GTS 3.8.3 are consistent with STS 3.8.6 and the ESBWR design, GTS 3.8.3 and bases are acceptable.

GTS 3.8.4, which is applicable in Modes 1, 2, 3, and 4, requires inverters to be operable to support the three divisions of uninterruptible ac electrical power distribution required by GTS LCO 3.8.6. The staff has concluded that the actions of GTS 3.8.4 are acceptable as described

below in the evaluation of RAI 16.2-82. The staff also concludes that the LCO, action, and surveillance requirements of GTS 3.8.4 are consistent with STS 3.8.7 and the ESBWR design. Therefore, GTS 3.8.4 and bases are acceptable.

GTS 3.8.5, which is applicable in Modes 5 and 6, requires inverters to be operable to support the uninterruptible ac electrical power distribution divisions required by GTS LCO 3.8.7. The staff has concluded that the actions of GTS 3.8.5 are acceptable as described below in the evaluation of RAI 16.2-82. The staff also concludes that the LCO, action, and surveillance requirements of GTS 3.8.5 are consistent with STS 3.8.8 and the ESBWR design. Therefore, GTS 3.8.5 and bases are acceptable.

RAI 16.2-55. The staff asked the applicant to justify its proposal to use float current monitoring to determine battery state of charge (SOC), instead of a SR for measuring battery cell electrolyte specific gravity. RAI 16.2-55 was tracked as an open item in the SER with open items. In response, the applicant committed to propose, upon final resolution of the staff's concerns with TSTF-360, a surveillance that conforms to the STS to the extent practicable and consistent with the ESBWR design. TSTF-360 is to be replaced with TSTF-500, "DC Electrical Rewrite—Update to TSTF-360," which was scheduled to be submitted by July 2007. Subsequent to its response, the applicant issued DCD Revision 3. This revision proposed that specific gravity measurements be replaced with float current monitoring to determine the battery SOC. To accept this proposal, the staff needed confirmation from the VRLA battery manufacturer that float current monitoring can accurately indicate the battery SOC during steady-state and discharge conditions. If float current monitoring does not indicate 100-percent SOC, the staff would have requested that the COL applicant commit to additional design margins in the battery sizing calculations to compensate for measurement uncertainty, and that the GTS bases specify these design margins. In DCD Tier 2, Revision 6, and in response to RAI 8.3-62, the applicant changed the type of battery to VLA and retained the proposed SR for float current measurements consistent with the STS. In addition, the applicant revised GTS 5.5.10, "Battery Monitoring and Maintenance Program," to address specific gravity. This specification states, "The following programs shall be established, implemented, and maintained....This program provides for battery restoration and maintenance, which includes the following:....A requirement to obtain specific gravity readings of all cells at each discharge test, consistent with manufacturer recommendations." This provision is consistent with staff comments that were subsequently incorporated into TSTF-500, Revision 2, which was submitted for staff review by the industry owners group TSTF. Battery-parameter-related COL information, such as COL Item 3.8.3-1 in DCD Tier 2, Table 16.0-1-A, stipulates that use of battery float current instead of battery cell specific gravity to indicate that the battery is fully charged is acceptable "provided the battery manufacturer has confirmed the acceptability and acceptance criteria, and that battery capacity includes margin for state of charge uncertainty." The staff finds that the battery-parameter-related COL items listed in DCD Table 16.0-1-A will ensure that use of battery float current to indicate battery state of charge is adequately justified. The staff also finds that the battery monitoring and maintenance program specification will ensure that battery cell electrolyte specific gravity measurements will be obtained as recommended by the battery manufacturer to confirm battery state of charge during a battery discharge test. Therefore, RAI 16.2-55 is resolved.

RAIs 16.2-57, 16.2-87, and 16.2-184. In RAI 16.2-57, the staff asked the applicant to include a value for the minimum acceptable pilot cell temperature. In response, the applicant committed to propose, upon final resolution of the staff's concerns with TSTF-360, a surveillance that conforms to the STS to the extent practicable and consistent with the ESBWR design. TSTF-360 is being replaced by TSTF-500, which was issued for staff review. Subsequent to its

response, the applicant issued DCD Revision 3. This revision replaced the requirements in Required Action 3.8.3.D.1 and SR 3.8.3.4 for pilot cell temperature with battery room temperature. The revised DCD did not justify using battery room temperature and did not state whether the design includes continuous monitoring of the battery room temperature with high and low alarms in the MCR. Since battery cell temperature could change for reasons other than ambient conditions (e.g., power flow, resistivity issues/internal shorts), the staff determined that new SRs should be specified for the battery pilot cells and connected cells. The staff also noted that the surveillance frequency should specify taking temperature measurements at the negative post of battery pilot cells every 31 days and at the negative post of connected cells every 92 days. The issues in RAI 16.2-87 and RAI 16.2-184 are similar to the issue in RAI 16.2-57. Therefore, the staff considered RAIs 16.2-87 and 16.2-184 to be resolved for tracking purposes. RAI 16.2-57 was being tracked as an open item in the SER with open items. In DCD Tier 2, Revision 6, and in response to RAI 8.3-62, GEH changed the type of battery to VLA and revised the action and surveillance requirements of GTS 3.8.3, as well as the affected bases sections. GEH also changed GTS 5.5.10, "Battery Monitoring and Maintenance Program," to be consistent with the changes proposed in TSTF-500, Revision 1. See Section 8.3 of this report for additional evaluation of the VLA battery-related changes addressed by the response to RAI 8.3-62 and incorporated in DCD Tier 2, Revision 6. Based on the resolution of RAI 8.3-62, RAI 16.2-57 is resolved.

RAI 16.2-122 GTS 3.8.3 includes required actions and SRs for battery room temperature. The staff asked the applicant to explain the basis for battery room temperature and why the DCD or GTS bases do not require continuous monitoring of the battery room temperature with alarms in the MCR when room temperature is below or above established design limits. The staff pointed out that battery cell temperature could change for reasons other than ambient conditions (e.g., power flow, resistivity issues/internal shorts), and for this reason, requested that the applicant specify a new LCO for the battery pilot cells and connected cells. The surveillance frequency associated with these LCOs should specify that the battery pilot cell temperature at the negative post be measured every 31 days and at the negative post of connected cells every 92 days. In DCD Tier 2, Revision 6, and in response to RAI 8.3-62, the applicant changed the type of battery to VLA and revised GTS 3.8.3 to include a SR for battery pilot cells and connected cells consistent with the STS. Therefore, RAI 16.2-122 is resolved.

RAI 16.2-123 The staff asked the applicant to explain how battery room temperature will be maintained during loss of ac power. Battery performance is dependent on battery temperature. The applicant should provide assurance that the battery will perform its intended function without ac power to the battery room ventilation and air conditioning systems. The staff asked the applicant to discuss battery margins (i.e., aging margin, design margin, temperature correction factor, and float current monitoring uncertainty for 100-percent SOC) and the potential for thermal runaway. In DCD Tier 2, Revision 6, and in response to RAI 8.3-62, the applicant changed the type of battery to VLA. Accordingly, the applicant revised GTS 3.8.3 to include SRs consistent with the STS for (1) battery pilot cell electrolyte temperature and float voltage, and (2) connected cell electrolyte level and float voltage. The applicant also removed the previously proposed SR on battery room temperature. Therefore, RAI 16.2-123 is resolved.

RAI 16.2-124 Based on DCD Tier 2, Revision 4, the staff requested that GEH justify its decision to not follow IEEE Standard 1188-2005, "IEEE Recommended Practice for Maintenance, Testing, and Replacement of Valve-Regulated Lead-Acid (VRLA) Batteries for Stationary Applications," in proposed GTS SR 3.8.3.6. The proposed SR required battery capacity verification every 60 months and every 12 months when the battery showed degradation or reached 85 percent of expected life. IEEE Standard 1188-2005, however, recommends that the

performance test interval should not be greater than 25 percent of the expected service life or 2 years, whichever is less. In response, the applicant proposed to revise the SR 3.8.3.6 frequency to “24 months and 12 months when battery shows degradation or has reached 85% of the expected life.” This frequency is consistent with IEEE Standard 1188-2005. Should the VRLA battery service life be found to be less than 8 years, for example from testing, then the 24-month frequency would need to be reduced.

In a follow-up question to the applicant’s response to RAI 16.2-124, the staff pointed out that the proposed minimum battery capacity of 80 percent in SR 3.8.3.6 is applicable to VLA batteries, not VRLA batteries. The staff requested that the applicant revise SR 3.8.3.6 to state, “Verify each required battery capacity is greater than or equal to 90% of the manufacturer’s rating when subjected to a performance discharge test {or a modified performance discharge test}.” This is consistent with the proposed bases and Section 6.3 of IEEE Standard 1188-2005. The staff proposed that the COL applicant provide documentation to justify the use of the modified performance discharge test for VRLA batteries in SR 3.8.3.6 and that the 80-percent battery capacity limit for the performance discharge test be bracketed in SR 3.8.3.6 as an item for the COL applicant to determine based on battery sizing.

However, in DCD Tier 2, Revision 6, GEH changed the battery type from VRLA to VLA, referenced IEEE Standard 450-2002, removed the option to perform a modified performance discharge test, and revised SR 3.8.3.6 to be consistent with STS SR 3.8.6.6, including the associated frequencies. On the basis of the changes made in DCD Revision 6, RAI 16.2-124 is resolved.

RAI 16.2-126 DCD Revision 4, GTS 3.8.1, Required Action A.2, states that, if one or both required battery chargers are inoperable on one required division, the associated battery must be returned to the fully charged condition. The bases specify a fully charged condition as either three consecutive hourly current readings with a change of “less than {0.5} amps” or a float current of “less than {2} amps.” The staff stated that GTS 3.8.1, not the bases, must define the fully charged condition. In addition, the staff noted that the applicant gave no technical justification for three consecutive hourly readings with a change of “less than {0.5} amps” in lieu of a float current of “less than {2} amps.” RAI 16.2-126 was being tracked as an open item in the SER with open items.

In response, GEH described two methods for determining battery SOC and stated that these methods are based on current monitoring because monitoring the electrolyte specific gravity of VRLA batteries is not feasible, and referenced IEEE Standard 1188-2005. GEH also stated that a third method for determining SOC is monitoring the float current, which is specifically designed for a battery being maintained in standby service at float voltage and consistent with the STS, which are based on the use of VLA batteries. GEH reasoned that this third method could be applied to VRLA batteries and noted that chemical changes occur within the VRLA battery, as they do in the VLA battery, as a result of the aging process. These chemical changes will cause the float current for a fully charged VRLA battery to increase with battery age. Therefore, unless the float current acceptance criterion is periodically increased, this method could result in a conservative but incorrect determination that a fully charged ESBWR VRLA battery is inoperable. Because of this, in DCD Tier 2, Revision 6, GEH revised two reviewer’s notes associated with proposed COL Items 3.8.1-2 and 3.8.3-1 (both entitled, “Acceptance criteria for verification that battery is fully charged.” in DCD Tier 2, Table 16.0-1-A) by deleting COL Item 3.8.1-2 and adding the following statement to COL Item 3.8.3-1, denoted by underlining:

Provide acceptance criteria for verification that battery is fully charged consistent with battery manufacturer recommendations. Use of float current monitoring option requires that battery manufacturer confirm acceptability and acceptance criteria and that battery capacity includes margin for state of charge uncertainty.

However, in DCD Revision 6, GEH also changed the battery type from VRLA to VLA, and changed DCD Revision 5 by replacing GTS 3.8.1, Action A, which removed language about verifying the battery is fully charged, and changing GTS 3.8.3, Required Action B.2 from "Verify battery is fully charged" to "Restore battery [float current < 30 amps]." (See discussion of RAI 16.2-82 in this section of this report.) These changes are consistent with the equivalent requirements in STS 3.8.4, Required Action A.2, and STS 3.8.6, Required Action B.2. The applicant also made conforming changes to the bases. Based on the applicant incorporating these changes in DCD Tier 2, Revision 6, RAI 16.2-126 is resolved.

RAI 16.2-129 The bases for LCO 3.8.1, "DC Sources," state that all safety-related Class 1E loads are isolated from the IPC buses by diodes on the output of both the safety-related rectifiers and the 250-V dc bus associated with the dc sources. The staff asked the applicant to explain why there are no SRs to periodically verify that the blocking diodes are operable. RAI 16.2-129 was being tracked as an open item in the SER with open items. In response, GEH committed to add SR 3.8.1.4 and associated bases to require verification every 24 months that the output diodes for the battery chargers and safety-related rectifiers do not allow current to flow from the dc source to an IPC bus that is deenergized or has degraded voltage. GEH stated that SR 3.8.1.4 will periodically verify that the output diodes for the battery chargers and safety-related rectifiers function to prevent degradation of the safety-related dc power system by the nonsafety-related ac power system, as described in DCD Tier 2, Section 8.1.5.2. GEH also committed to revise SR 3.8.2.1 and the associated bases to require compliance with SR 3.8.1.4 for required battery chargers and associated safety-related rectifiers in Modes 5 and 6. GEH also committed to make conforming changes to DCD Tier 1, Sections 2.13.3 and 2.13.5 to establish, in Table 2.13.5-2, ITAAC requirements to verify that the output diodes for the safety-related rectifiers prevent degradation of the safety-related dc power system by the nonsafety-related ac power system. Specifically, SR 3.8.1.4 states, "Verify the output diode for each required battery charger and safety-related rectifier connected to the Isolation Power Center bus prevents reverse current flow" and has a 24-month frequency. The staff finds the proposed changes acceptable and verified their incorporation in DCD Revision 5. Therefore, RAI 16.2-129 is resolved.

RAIs 16.2-56 and 16.2-86 The staff asked the applicant to provide a value for the minimum acceptable pilot cell voltage in SR 3.8.3.2. RAI 16.2-86 is related to the minimum acceptable pilot cell float voltage. The minimum acceptable pilot cell float voltage is a bracketed value, and it is the responsibility of the COL applicant to ensure that the PTS specify the minimum acceptable voltage. RAI 16.2-56 is related to the pilot cell selection criteria. According to DCD Revision 3, Chapter 16B, the bases for SRs 3.8.3.2 and 3.8.3.5 state that the cell selection criterion is the lowest cell voltage in the series string following the quarterly surveillance. The quarterly surveillance verifies that the float voltage of each connected cell of each required battery is greater than or equal to the minimum acceptable voltage. This selection criterion for the pilot cell will provide reasonable assurance that no cell voltage is less than the minimum acceptable voltage between quarterly surveillances. Based on the preceding discussion, the staff finds the response acceptable. Therefore, RAIs 16.2-56 and 16.2-86 are resolved.

RAIs 16.2-60 and 16.2-82 Based on its review of DCD Revision 1, the staff requested that the applicant explain and justify the action requirements for Condition A of GTS 3.8.1, "24-hour DC

Sources - Operating.” (This request also applied to the action requirements for Condition A of GTS 3.8.2, “72-hour DC Sources - Operating.”) Specifically, RAI 16.2-60 stated the following:

[The bases for GTS] 3.8.1, Required Action A.3, [on] page B 3.8.1-5, should specify the power supply requirements for the alternate means of restoring battery terminal voltage. Explain whether the alternate means of restoring battery terminal voltage should rely on a power source that is independent of offsite power in order to justify the 7 day completion time.

The applicant’s response to RAI 16.2-60 pointed out that the staff’s concern was similar to Staff Concern 1 contained in NRC’s letter to the operating reactor owners’ group Technical Specifications Task Force, “Request for Public Meeting to Discuss Enclosed Document Electrical Engineering Branch Concerns with Technical Specifications Task Force (TSTF)-360, Revision 1 DC Electrical Rewrite.” The applicant stated, “Upon final resolution of the staff concerns with TSTF-360, the ESBWR [design certification application] will address any agreed to changes to NUREG–1434.” The staff notes that the industry’s latest proposal to resolve issues with TSTF-360 is provided in TSTF-500, Revision 1, “DC Electrical Rewrite - Update to TSTF-360.” In DCD Tier 2, Revision 2, Chapters 16 and 16B, the applicant revised the dc sources specifications and bases by eliminating 24-hour safety-related dc sources and requiring just three of the four divisions of dc sources to be operable in Modes 1, 2, 3 and 4, since three is the minimum number to meet the single-failure criterion. GEH also reduced the 7-day completion time for an inoperable dc source battery charger (equivalent to the condition of one or both required battery chargers inoperable on one required division (i.e., one dc source division) to 72 hours. However, DCD Revision 2 did not resolve the concern about whether the alternate means of restoring battery terminal voltage (Required Action A.1) should rely on a power source that is independent of offsite power. In DCD Revisions 2 and 3, the bases for Required Action A.1 stated the following (emphasis added):

Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status *or providing an alternate means of restoring battery terminal voltage* to greater than or equal to the minimum established float voltage.

The staff finds that this basis is acceptable because the only practical “alternate means” in the ESBWR design would be the backup battery charger. In addition, the shortened completion time of 72 hours to restore one battery charger in one division (GTS 3.8.1, Required Action A.3, in DCD Revision 6) is reasonable considering that the affected division can still supply all of its loads with just one battery or one battery charger supplying one dc bus and one inverter. Further, in DCD Revision 6, for the condition of “DC Sources associated with two DC Electrical power distribution buses on one required division inoperable,” GTS 3.8.1, Required Action B.1, requires restoring the required dc sources on one dc electrical power distribution bus to operable status within 8 hours. This is also reasonable, since the two remaining operable divisions are capable of initiating actuation of all safety functions assumed in the FSAR Chapter 15 analyses of design-basis events and accidents. Therefore, the staff considers RAI 16.2-60 to be resolved based on these reasons and the resolution of RAI 16.2-82, which is discussed below.

In RAI 16.2-82, the staff requested that the applicant provide the basis for the proposed required action completion times in DCD Revision 1 for GTS 3.8.1, Action B, and GTS 3.8.5, Action A. This request was also relevant to GTS 3.8.2, Action B. These actions stated the following:

GTS 3.8.1 "24-hour DC Sources - Operating" (Modes 1, 2, 3, 4) (Divisions 1, 2, 3, 4)

- Condition B. One 24-hour DC Source battery inoperable.
- Required Action B.1 Restore 24-hour battery to OPERABLE status.
- Completion Time 48 hours

GTS 3.8.2 "72-hour DC Sources - Operating" (Modes 1 and 2) (Divisions 1 and 2)

- Condition B. One 72-hour DC Source Division inoperable for reasons other than Condition A (One required 72-hour DC Source battery charger inoperable.)
- Required Action B.1 Restore 72-hour DC Source Division to OPERABLE status.
- Completion Time 30 days

GTS 3.8.5 "Inverters - Operating" (MODES 1 and 2; MODES 3 and 4, except the 72-hour inverters are not required to be OPERABLE.)

- Condition A. One inverter inoperable.
- Required Action A.1 Restore inverter to OPERABLE status.
- Completion Time 24 hours for 24-hour inverter AND 30 days for 72-hour inverter

In response, subsequent to submission of DCD Revision 2, the applicant stated the following:

The ESBWR design consists of four divisions with two 72-hour batteries per division for a total of eight safety-related batteries. The ESBWR no longer includes 24-hour batteries. The ESBWR design ensures single failure tolerance is maintained when any three of the four divisions of DC and uninterruptible AC electrical power sources are operable and the associated distribution systems are energized. The design described is reflected in Revision 2 of DCD, Tier 2, Chapter 16, "Technical Specifications," which requires operability of only three of the four DC and uninterruptible AC electrical divisions.

The applicant noted that DCD Revision 1 actions were also changed. The corresponding actions in DCD Revisions 2 and 3 stated the following:

GTS 3.8.1, "DC Sources - Operating" (Modes 1, 2, 3, 4) (Three Divisions)

- Condition B. One or more DC Sources inoperable on one required division for reasons other than Condition A (one or both required battery chargers inoperable on one required division).
- Required Action B.1 Restore DC Sources to OPERABLE status.
- Completion Time 24 hours

GTS 3.8.4, "Inverters - Operating" (MODES 1, 2, 3, and 4) (Three Divisions)

- Condition A. One required division inoperable.
- Required Action A.1 Restore required division to OPERABLE status.
- Completion Time 24 hours

Note that DCD Revision 3, GTS 3.8.1 replaced the two previous specifications for dc sources - operating. Also note that in the renumbered inverter specification, GTS 3.8.4, Condition A addressed both inverters in a division being inoperable and noted that both must be restored to operable status in order to exit the condition. The applicant justified the proposed dc source completion time based on the enhanced design of the dc sources and the electrical power distribution in the ESBWR as compared to the BWR/6. The applicant justified the inverter division completion time based on the similarity of the BWR/6 and ESBWR inverter designs in that both assume that the ac bus is powered via the nonsafety-related constant voltage transformer from an offsite or onsite ac source. Subsequent to DCD Revision 5, however, the applicant removed the constant voltage transformer from the ESBWR design.

In RAI 16.2-82 S01, the staff asked the following of GEH:

1. Explain in greater detail the design differences between BWR/6 and ESBWR that justify the 24-hour completion time in GTS 3.8.1, Action B, for restoring ESBWR dc sources in one required division to operable status or change it to a shorter completion time that the design difference can justify.
2. Provide additional justification for the 24-hour completion time in GTS 3.8.4, Action A, for restoring the required division to operable status or change it to an 8-hour completion time, which is consistent with the 8-hour completion time of Action B of GTS 3.8.6 for restoring one required division of uninterruptible ac electrical power distribution to operable status.
3. Revise required action completion times in GTS 3.8.6 for restoring electrical power distribution buses to operable status to be consistent with the completion times in GTS 3.8.1 and 3.8.4, if shorter completion times are proposed in response to Items 1 and 2 above.
4. Provide additional justification for the periodic 24-hour completion time for GTS 3.8.1, Required Action A.2, to verify that the battery is in a fully charged condition or propose and justify a periodic completion time much shorter than 24 hours.

Following subsequent conference calls between GEH and the staff, GEH responded to RAI 16.2-82 S01 by proposing action requirements for GTS 3.8.1, 3.8.2, 3.8.4, 3.8.5, 3.8.6, and 3.8.7 consistent with the following descriptions:

- Specify a condition in which just one half of one division is inoperable with a 72-hour completion time to restore the division to operable status in Modes 1, 2, 3, 4, 5 and 6.
- Specify a condition in which both halves of one division are inoperable with an 8-hour completion time to restore half of the division to operable status, for Modes 1, 2, 3, and 4, and a completion time of immediately to declare affected (or associated supported) features

inoperable (or stop core alterations and operations with a potential for draining the reactor vessel and initiate action to restore required features - dc sources, inverters, dc buses, or uninterruptible ac buses to operable status) for Modes 5 and 6.

The proposed action requirements for half of one required division being inoperable in Modes 1, 2, 3, 4, 5 and 6 are reasonable because the degraded division is still capable of powering its supported safety systems, although in some cases for less than the designed 72-hour period following a design-basis event, but for greater than 36 hours. Hence following a design-basis event in this condition, safety-related electrical power can withstand an additional active failure and still perform its intended support functions for a significant fraction of the 72-hour period. It is customary in standard TS to allow 72 hours for a loss of redundancy in a safety system consisting of two 100-percent capacity subsystems because of the low probability of a design-basis event occurring during the specified time to restore the redundant subsystem to operable status. Since the ESBWR design offers additional capability over that assumed for a similar condition in the BWR/6 design, the staff finds the 72-hour completion time to restore the inoperable half of one required division acceptable.

The proposed action requirements for a complete loss of redundancy (both halves of one required division are inoperable) in Modes 1, 2, 3, and 4, which require restoring at least half of the inoperable division to operable status within 8 hours, are reasonable considering the capability of the remaining two operable divisions to ensure a reactor scram and automatic actuation of all safety systems (ADS, GDCS, ICS, main steam and containment isolation, SLC, and CRHAVS), should a design-basis event occur. This capability exceeds that of the BWR/6 which would only retain half its safety system actuation capability in a similar condition. The proposed 8-hour time allowed to restore half of the inoperable division to operable status is acceptable because of the low probability that a design-basis event will occur during this time.

The proposed action requirements for a complete loss of redundancy in Modes 5 and 6, which require immediately declaring supported features inoperable, or suspending core alterations, suspending operations with a potential for draining the reactor vessel, and initiating action to restore the inoperable required features to operable status, are consistent with the BWR/6 STS. These action requirements will ensure that effective remedial measures will be taken to either minimize the chance of a shutdown event (e.g., drop of an irradiated fuel assembly) occurring while the unit is vulnerable to another failure, which could result in a loss of a safety function, or to prevent a shutdown event from occurring at all. Therefore, these actions are acceptable.

The staff also requested that the applicant provide additional justification for the periodic 24-hour completion time for GTS 3.8.1, Required Action A.2, to verify that the battery is in a fully charged condition or to propose and justify a periodic completion time much shorter than 24 hours. In response to RAI 16.2-82 S01, the applicant proposed to remove GTS 3.8.1, Action A, since the revised action requirements adequately addressed the condition of an inoperable battery charger dc source. In addition, the applicant proposed to replace Action B in GTS 3.8.3, "Battery Parameters," with two actions - one for the condition of one battery on one required division with "[float current > 30 amps]," and the other for the condition of both batteries on one required division with "[float current > 30 amps]." Similar to the resolution of the action requirements for dc sources, inverters, and distribution buses, GEH proposed that for one battery on one required division with "[float current > 30 amps]," that 24 hours be allowed to restore the battery "[float current < 30 amps]." This time is reasonable since the affected division retains the capability to initiate actuation of all its supported safety systems because half of the division remains operable, although for less than the design 72-hour period, and the remaining two divisions can initiate actuation of all safety systems. This completion time is also

consistent with a reviewer's note in the BWR/6 STS 3.8.6 bases concerning the completion time to restore a discharged battery to a fully charged state, as indicated by the battery's float current. For these reasons the proposed 24-hour completion time is acceptable.

For the condition of two batteries with "[float current > 30 amps]" on one required division, GEH proposed that 8 hours be allowed to restore one battery "[float current < 30 amps]." This time is reasonable since the remaining two divisions can initiate actuation of all safety systems. Also, it is unlikely that the second battery in a required division will be significantly discharged because of testing (i.e., a service discharge test). Therefore, 8 hours is expected to afford sufficient time to recharge the partially discharged battery, so that battery "[float current < 30 amps]." For these reasons, the staff finds the 8-hour completion time acceptable.

Based on the above evaluation of the GEH response and proposed action requirements for electrical power system specifications, RAI 16.2-82 is resolved.

The GTS for electrical power systems implement modified versions of the STS for the dc and vital ac electrical power systems. The staff finds that the GTS for electrical power systems are essentially equivalent to the STS for the corresponding electrical power system functions. For those cases in which the GTS do not include STS for electrical power systems, ESBWR design differences provide sufficient justification for such omissions. Therefore, the staff finds the GTS and bases for electrical power systems acceptable.

16.2.12 ESBWR GTS Section 3.9, "Refueling Operations"

The ESBWR GTS for refueling operations compare closely to the corresponding STS provisions, with only a few exceptions. The correspondence between Section 3.9 of the ESBWR GTS and Section 3.9 of the STS is as follows:

<u>STS</u>	<u>GTS</u>	<u>GTS TITLE (*STS TITLE)</u>
3.9.1*	3.9.1	Refueling Equipment Interlocks (*same)
3.9.2*	3.9.2	Refuel Position One-Rod/Rod-Pair-Out Interlock (*Refuel Position One-Rod-Out Interlock)
3.9.3*	3.9.3	Control Rod Position (*same)
3.9.4*	3.9.4	Control Rod Position Indication (*same)
3.9.5*	3.9.5	Control Rod OPERABILITY - Refueling (*same)
3.9.6*	3.9.6	Reactor Pressure Vessel (RPV) Water Level (*[RPV] Water Level - [Irradiated Fuel])
None	3.9.7	Decay Time
3.9.7*	None	(*[RPV] Water Level - [New Fuel])
3.9.8*	None	(*RHR - High Water Level)
3.9.9*	None	(*RHR - Low Water Level)

The GTS for refueling equipment interlocks, refuel position one-rod/rod-pair-out interlock, control rod position, control rod position indication, control rod operability - refueling, and RPV water level contain no significant differences from the corresponding STS requirements. Therefore, GTS 3.9.1, 3.9.2, 3.9.3, 3.9.4, 3.9.5, and 3.9.6, and bases are acceptable.

The GTS do not include a specification for the nonsafety-related normal SDC system, which corresponds to the RHR system specified in the STS. The ESBWR employs passive safety-related methods for removing decay heat when the plant is in the refueling mode. (One such method is feed-and-bleed from the GDCS pool. If this method is not used, then decay heat may be removed by refueling cavity boiling if the refueling canal is full and the RPV upper internals are removed.) Because the accident analyses do not assume that the SDC system will function in a loss-of-cooling event during refueling shutdown conditions, the SDC system does not satisfy the criteria of 10 CFR 50.36(c)(2)(ii). Therefore, omitting specifications corresponding to the STS RHR requirements during refueling operations is acceptable.

The time interval between when the reactor was last critical and the initial movement of an irradiated fuel assembly from the reactor core is a key assumption in the dose consequence estimates of an ESBWR design-basis fuel-handling accident analysis, as well as in the spent fuel pool cooling requirements. As such, this decay time satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) and must be included in an LCO in the ESBWR GTS, preferably in GTS Section 3.9. The applicant proposed a decay time specification in ESBWR GTS 3.9.7, "Decay Time." This specification provides a decay time limit and associated action and SRs consistent with the ESBWR fuel-handling accident analysis, STS format, and requirements of 10 CFR 50.36. Therefore, GTS 3.9.7 and bases are acceptable.

RAI 16.2-76 DCD Tier 2, Section 9.1.2.7, states that on a complete loss of the FAPCS active cooling capability and under the condition of maximum heat load, sufficient quantity of water is available in the spent fuel pool above the top of active fuel (TAF) level to allow boiling for 72 hours and still have the TAF at least 3.0 m (10 ft) submerged under water. The water level necessary to provide this heat removal capacity constitutes an initial condition of a transient analysis for a loss of forced cooling. The loss of inventory presents a challenge to a fission product barrier in that water cooling is necessary to assure protection of the fuel cladding. However, the GTS include no LCO for this initial spent fuel pool level. The staff asked that the applicant describe how the initial water level necessary to satisfy this transient analysis is included in an LCO consistent with the requirements of 10 CFR 50.36(c)(2)(ii), Criterion 2. In response, the applicant stated that the water level assumed in this analysis is already bounded by the water level required by LCO 3.7.5, which is included in the GTS as an initial condition for the fuel handling accident safety analyses described in DCD Tier 2, Section 15.1.4, "Fuel Handling Accident." The applicant also stated that no LCO is required for this initial condition because "the complete loss of the FAPCS is not an analyzed AOO or DBA." The applicant thus proposed no change to the GTS.

In RAI 16.2-76 S01 the staff requested that the applicant provide an analysis evaluating the anticipated occurrence of a loss of the FAPCS and an LCO for the initial condition required for spent fuel pool inventory to satisfy the analysis. In response, the applicant proposed to establish RTNSS short-term availability controls for spent fuel pool water level (AC 3.7.3, "SFP Water Level") and the fire protection water supply system emergency makeup to the spent fuel pool (AC 3.7.1, "Emergency Makeup Water"). The applicant proposed to add these availability controls to the ACM in DCD Tier 2, Appendix 19A. Subsequently as discussed in Section 9.1.3 of this report, the applicant removed the availability control for spent fuel pool water level and revised GTS 3.7.5 to require spent fuel pool level to be 10.26 m (33.7 ft) above the top of irradiated fuel assemblies and that pool water temperature be ≤ 60 degrees C (140 degrees F). These level and temperature limits apply to both the fuel building spent fuel storage pool and the deep pit area of the reactor building buffer pool. The applicant also added appropriate action and surveillance requirements for pool temperature. The staff finds the revised GTS 3.7.5 requirements and associated bases changes to be acceptable because they are

consistent with the boil-off analysis assumptions, as discussed in Section 9.1.3 of this report, and will ensure that in the event of a loss of FAPCS cooling, the level in the spent fuel pool and buffer pool will remain above the top of the irradiated fuel assemblies for 72 hours without makeup. Therefore, RAI 16.2-76 is resolved.

RAI 16.2-77 The staff asked the applicant to describe how the GTS include an LCO for a makeup water system for the reactor building buffer pool. The staff asserted that such a system satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii) as the primary success path to mitigate a loss of coolant inventory caused by a failure of the refueling seal around the reactor vessel or a failure of the inclined fuel transfer system (IFTS) interlocks. In response, GEH stated that the refueling bellows seal is designed to seismic Category I requirements; therefore, a rapid loss of coolant through this seal is not credible. GEH also stated that the IFTS is designed with sufficient redundancy and diversity to ensure that there are no modes of operation that will allow simultaneous opening of any set of valves that could cause draining of the water from the upper (buffer) pool in an uncontrolled manner. Since these events are not deemed credible, and are therefore not postulated in the safety analysis in DCD Tier 2, Chapter 15, GEH concludes that an LCO is not required for the FAPCS, which is designed to supply the makeup water to the buffer pool. However, AC 3.7.1, "Emergency Makeup Water," requires the availability of FAPCS makeup capability. GEH revised DCD Tier 2, Table 3.2-1 and Section 6.2.1.1.2, to show that the refueling bellows is a part of the containment system and is designed to seismic Category I. In addition, GEH removed "refueling bellows" from the list of refueling equipment in DCD Tier 2, Table 9.1-4. Based on the applicant's response, RAI 16.2-77 is resolved.

RAI 16.2-99 The staff asked GEH why the third paragraph in the "Background" section of the bases for STS 3.9.2, "Refuel Position One-Rod-Out Interlock," was replaced with another paragraph in the bases for GTS 3.9.2, "Refuel Position One-Rod/Rod-Pair-Out Interlock." This STS paragraph states, "This specification ensures that the performance of the refuel position one-rod-out interlock in the event of a DBA meets the assumptions used in the safety analysis of FSAR Section [15.4.1.1]." In DCD Revision 5, the first sentence of the GTS paragraph states, "The refuel position one-rod/rod-pair-out interlock prevents the selection of a second control rod for movement when any other control rod or control rod pair is not fully inserted ([DCD] Section 7.7.2)." In response, GEH stated that the control rod withdrawal error during refueling (DCD Tier 2, Revision 5, Section 15.3.7) is categorized for the ESBWR as an infrequent incident, but not a DBA, as it is for the BWR/6 design. Since the proposed paragraph is consistent with the ESBWR design and safety analysis, it is acceptable and RAI 16.2-99 is resolved. The staff notes that this RAI was mistakenly associated with the resolution of RAI 4.6-23 regarding the CRDA, which DCD Tier 2, Revision 5, Section 15.4.6.3, discusses.

RAI 16.2-101 The staff requested that the applicant adopt STS 3.9.7, "RPV Water Level - New Fuel or Control Rods," to ensure that new fuel assemblies or control rods are not moved over irradiated fuel assemblies seated within the RPV unless the water above the top of the irradiated fuel assemblies seated within the RPV is sufficient to retain iodine fission product activity in the water in the event of a fuel-handling accident resulting in the release of fission product activity from irradiated fuel assemblies. RAI 16.2-101 was tracked as an open item in the SER with open items. In response, the applicant stated that dropping a new fuel assembly and dropping a control rod onto irradiated fuel are not DBAs for the ESBWR. The applicant therefore concluded that an LCO for RPV level in Mode 6 while moving new fuel or control rods does not meet Criterion 2 of 10 CFR 50.36(c)(2)(ii). In RAI 16.2-101 S01, the staff requested that GEH add to GTS 3.9.6 the following applicability condition: "During movement of new fuel assemblies or handling of control rods within the RPV, when irradiated fuel assemblies are seated within the RPV." The staff also asked that the applicant make corresponding bases

changes, consistent with BWR/6 STS 3.9.6, its bases, and the STS reviewer's note which states that "LCO 3.9.6 is written to cover new fuel and control rods as well as irradiated fuel." The staff made this request because there appeared to be no ESBWR design-specific reason to deviate from the BWR/6 STS 3.9.6. In response, GEH agreed to restore consistency with the STS by adding the above applicability condition to GTS 3.9.6 and making conforming bases changes. Therefore, RAI 16.2-101 is resolved.

The GTS for refueling operations implement modified versions of the STS for refueling operations. The staff finds that the GTS for refueling operations are essentially equivalent to the STS for the corresponding refueling constraints. For those cases in which the GTS does not include STS for refueling operations, ESBWR design differences provide sufficient justification for such omissions. Therefore, the staff finds the GTS and bases for refueling operations acceptable.

16.2.13 ESBWR GTS Section 3.10, "Special Operations"

The GTS associated with special operations correspond to the STS as follows:

<u>STS</u>	<u>GTS</u>	<u>GTS TITLE (*STS TITLE)</u>
3.10.1*	3.10.1	Inservice Leak and Hydrostatic Testing Operation (*same)
3.10.2*	3.10.2	Reactor Mode Switch Interlock Testing (*same)
3.10.3*	3.10.3	Control Rod Withdrawal - Shutdown (*Single Control Rod Withdrawal - Hot Shutdown)
3.10.4*	3.10.4	Control Rod Withdrawal - Cold Shutdown (*Single Control Rod Withdrawal - Cold Shutdown)
3.10.5*	3.10.5	Control Rod Drive Removal - Refueling (*Single Control Rod Drive Removal - Refueling)
3.10.6*	3.10.6	Multiple Control Rod Withdrawal - Refueling (*same)
3.10.7*	3.10.7	Control Rod Testing - Operating (*same)
3.10.8*	3.10.8	SHUTDOWN MARGIN (SDM) Test - Refueling (*same)
3.10.9*	None	(*Recirculation Loops - Testing)
None	3.10.9	Oxygen Concentration - Startup Test Program
None	3.10.10	Oscillation Power Range Monitor (OPRM) - Initial Cycle

The GTS associated with special operations implement modified versions of the STS for special operations. The staff finds that these specifications are essentially equivalent to the STS for the corresponding testing constraints and format and usage rules. The staff finds that for those cases in which a GTS provision differs from the equivalent STS provision or a GTS corresponding to the STS has not been included, the ESBWR design provides sufficient justification for such differences.

RAI 16.2-65 The staff identified inconsistent action requirements related to GTS 3.10.1, "Inservice Leak and Hydrostatic Testing Operation," and GTS 3.6.3.1, "Reactor Building," as compared to the actions described in STS LCOs 3.6.1 and 3.3.6.2. Specifically, the STS require immediate suspension of testing, restoration of secondary containment and secondary containment isolation valve operability, and cooldown to less than 93.3 degrees C (200 degrees F) within 36 hours, if operability cannot be restored. In RAI 16.2-65, the staff requested that the

applicant provide technical justification for allowing scram time testing in Mode 5, with the reactor coolant temperature greater than 93.3 degrees C (200 degrees F) and with the reactor building inoperable for an extended time. In response, the applicant revised the note to GTS 3.10.1, Required Action A.1, to state that "Required Actions to be in MODE 3 include reducing average reactor coolant temperature to ≤ 93.3 °C (200 °F) within 36 hours." Activities that could further increase reactor coolant temperature or pressure are suspended immediately in accordance with Required Action A.1, and the reactor coolant temperature is reduced to establish normal Mode 5 requirements. The allowed completion time of 24 hours for Required Action A.2 is based on engineering judgment and provides sufficient time to reduce the average reactor coolant temperature. The staff considers this change acceptable for ensuring that reactor coolant temperature will be reduced to less than 93.3 degrees C (200 degrees F) within 36 hours, consistent with the actions described in the STS. Therefore, RAI 16.2-65 is resolved.

The staff concludes that the constraints specified for testing under special operations will protect the fuel cladding and the RCS pressure boundary. Therefore, the staff finds the GTS and bases for special operations to be acceptable.

16.2.14 ESBWR GTS Section 4.0, "Design Features"

The GTS design features correspond to, and are consistent with, those specified in the STS.

In response to RAI 9.1-129, GEH stated it will:

- Change the value of k-infinity shown in GTS 4.3.1.1.a and GTS 4.3.1.2.a from "1.35" to "1.32" to be consistent with NEDC-33374P, "Safety Analysis Report for Fuel Storage Racks Criticality Analysis for ESBWR Plants."
- Delete the adjective "beginning-of-life (BOL)" from the phrase "maximum beginning-of-life (BOL) lattice k-infinity" in GTS 4.3.1.2.a to be consistent with NEDE-33374P and the STS.
- Add a requirement equivalent to STS 4.3.1.2.c regarding the center-to-center storage spacing distance for fuel assemblies placed in the new fuel storage racks in the reactor building buffer pool. GEH stated that two values will be provided since the center-to-center storage spacing is dependent upon whether the assemblies are within the same or differing rows of a given fuel storage rack. Since the new fuel storage racks do not contain neutron poison material, GEH stated that GTS 4.3.1.2.c will not contain a reference to neutron poison material.

These changes are acceptable for the reasons stated in the evaluation of the response to this RAI in Section 9.1 of this report.

RAI 16.2-80 The staff asked GEH to clarify GTS 4.3.2, "Drainage," regarding the minimum elevation used for spent fuel storage pool drainage prevention features. In response, GEH resolved this RAI by revising GTS 4.3.2 to state the following:

4.3.2 Drainage

- 4.3.2.1 The Fuel Building spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below an elevation of 14.3 m (46.9 ft) above the floor of the pool.

- 4.3.2.2 The Reactor Building buffer pool deep pit is designed and shall be maintained to prevent inadvertent draining of the pool below an elevation of 16.2 m (53.1 ft.) above the floor of the deep pit area.

Based on consistency with the STS, the ESBWR DCD, and the resolution of RAI 16.2-80 and RAI 9.1-129, the staff concludes that GTS Section 4.0 is acceptable.

16.2.15 ESBWR GTS Section 5.0, “Administrative Controls”

The GTS administrative controls correspond to, and are consistent with, those specified in the STS.

The applicant proposed (GEH letter, dated February 26, 2009) to incorporate TSTF-511-A. The revised regulations (Volume 73, Page 16966, of the *Federal Register*) in Subpart I, “Managing Fatigue,” of 10 CFR Part 26, “Fitness for Duty Programs,” superseded the previously proposed working hour restrictions of GTS 5.2.2.d, which is deleted. This change is consistent with the STS convention that TS do not repeat requirements specifically contained in regulations. It is also consistent with the changes contained in TSTF-511-A. Therefore this change is acceptable.

The staff requested additional information regarding the Section 5.0 specifications, as described in the following RAIs.

RAI 16.2-68 The staff asked the applicant to justify excluding STS 5.5.3, “Post Accident Sampling,” from ESBWR GTS Section 5.5. The STS program contains a reviewer’s note which states, “[t]his program may be eliminated based on the implementation of NEDO-32991, Revision 0, ‘Regulatory Relaxation for BWR Post Accident Sampling Stations (PASS),’ and the associated NRC Safety Evaluation dated June 12, 2001.” In response, and in accordance with the reviewer’s note, the applicant stated that it planned to implement the guidance of NEDO-32991 and the associated NRC SER by revising the ESBWR DCD Tier 2 Appendix 1A and DCD Tier 2, Sections 7.5.2, 7.5.3, 9.3.2, 11.5, and others as necessary. The staff verified that GEH had incorporated the guidance into the appropriate DCD sections and noted that DCD Tier 2, Section 9.3.2.1 states that the process sampling system “design provides the capability to meet the requirements of NEDO-32991-A, ‘Regulatory Relaxation for BWR Post-Accident Sampling Stations (PASS).’” Therefore, RAI 16.2-68 is resolved.

RAI 16.2-69 At the staff’s request, the applicant incorporated TSTF-497-A into GTS 5.5.5, “Inservice Testing (IST) Program,” without deviation. This is acceptable because it is consistent with the staff’s position on limiting IST interval extensions. Therefore, RAI 16.2-69 is resolved.

RAI 16.2-89 The staff requested that the applicant verify that proposed GTS 5.5.10, “Battery Monitoring and Maintenance Program,” references the appropriate IEEE standard and includes all essential maintenance parameters. In response, the applicant stated that it had replaced its program proposal, as of Revision 3 to the DCD, to state the following:

This Program provides for battery restoration and maintenance, based on the recommendations of IEEE Standard 1188-2005, “IEEE Recommended Practice for Maintenance, Testing, and Replacement of Valve-Regulated Lead-Acid (VRLA) Batteries for Stationary Applications,” or of the battery manufacturer of the following:

- a. Actions to restore battery cells with float voltage < 2.18 V, and
- b. Actions to determine the cause and correct when cell temperatures deviate more than 3 degrees C (5 degrees F) from each other.

In a follow-up question, RAI 16.2-89 S01, the staff stated that it had not yet endorsed IEEE Standard 1188-2005 and asked the applicant to revise the program to state the following:

This Program provides for battery restoration and maintenance which includes the following:

- a. Actions to restore battery cells with float voltage < 2.18 V, and
- b. Actions to determine the cause and correct when cell temperatures deviate more than 3 degrees C (5 degrees F) from each other.
- c. Actions to verify that remaining cells are ≥ 2.14 VDC when a cell or cells have been found to be < 2.18 VDC.

RAI 16.2-89 S01 was being tracked as an open Item in SER with open items. In response, GEH revised GTS 5.5.10 to be consistent with the above recommendation by the staff, but combined proposed Item (c) with Item (a) since it is related to the same condition of discovering one or more battery cells less than 2.18 V. GEH also added a reference to SR 3.8.3.5, "Verify each required battery connected cell float voltage is $\geq [2.09]$ V," to Item (a), since this surveillance provides a more direct connection to the appropriate actions if a cell is discovered to be less than 2.14 V (i.e., Action A of Specification 3.8.3). The staff finds these changes acceptable.

As described in the evaluation of RAI 8.3-62 in Section 8.3 of this report, in DCD Revision 6 GEH changed its type of battery to VLA and replaced Item (b) with three additional items such that GTS 5.5.10 states the following:

This Program provides for battery restoration and maintenance, which includes the following:

- a. With battery cell float voltage [< 2.13] V, actions to restore cell(s) to [≥ 2.13] V and perform SR 3.8.3.5;
- b. Actions to equalize and test battery cells that had been discovered with electrolyte level below the minimum established design limit;
- c. Limits on average electrolyte temperature, battery connection resistance, and battery terminal voltage; and
- d. A requirement to obtain specific gravity readings of all cells at each discharge test, consistent with manufacturer recommendations.

The staff finds the proposed program elements acceptable because they are more conservative than those provided in the STS. Therefore, GTS 5.5.10 is acceptable and RAI 16.2-89 is resolved.

Based upon the above evaluations, the RAI resolutions, and consistency with the STS, the staff concludes that GTS Section 5.0 is acceptable.

16.2.16 Consideration of Generic Communications

Chapter 20 of this report lists generic communications. Those related to the TS and their dispositions are as follows:

GENERIC LETTERS

DISPOSITION

82-021, "Technical Specifications for Fire Protection Audits," October 6, 1982.	Not applicable; no longer in TS
82-023, "Inconsistency Between Requirements of 10 CFR 73.40(D) and Standard Technical Specifications for Performing Audits of Safeguards Contingency Plans," October 30, 1982.	Not applicable; no longer in TS
87-009, "Sections 3.0 and 4.0 of the Standard Technical Specifications on the Applicability of Limiting Conditions for Operation and Surveillance Requirements," June 4, 1987.	Superseded by STS
88-016, "Removal of Cycle-Specific Parameter Limits from Technical Specifications," October 3, 1988.	DCD Table 16.0-1-A , COL Item 5.6.3-1 for bracketed information - COLR
89-014, "Line-Item Improvements in Technical Specifications - Removal of the 3.25 Limit on Extending Surveillance Intervals," August 2, 1989.	Superseded by STS generic change process (TSTF travelers)
91-004, "Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle," April 2, 1991.	Adopted in ESBWR GTS
93-005, "Line-Item Technical Specification Improvements to Reduce Surveillance Requirements for Testing During Power Operation," September 27, 1993.	Superseded by STS
96-003, "Relocation of the Pressure Temperature Limit Curves and Low Temperature Overpressure Protection System Limits," January 31, 1996.	DCD Table 16.0-1-A, COL Items 1.1-1 and 5.6.4-1 for bracketed information - PTLR
03-001, "Control Room Habitability," June 12, 2003.	Closed based on adoption of TSTF-448-A

NEW GENERIC ISSUES

78, "Monitoring of Fatigue Transient Limits for Reactor Coolant System."

DISPOSITION

Issue 78 was resolved in NUREG-0933 with no action required. The staff's evaluation of fatigue effects is provided in section 3.12.6 of this report.

The above listed generic items are resolved for ESBWR based on the disposition listed above.

16.3 Conclusions

Based on its review of the proposed ESBWR GTS and GTS bases, the staff concludes that the proposed GTS and GTS bases are consistent with the regulatory guidance contained in the STS and STS bases. The proposed GTS and GTS bases contain design-specific parameters and additional requirements considered appropriate by the staff. The staff concludes that the proposed GTS and GTS bases comply with the requirements of 10 CFR 50.34, 10 CFR 50.36 and 10 CFR 50.36a and that they are therefore acceptable.

17. QUALITY ASSURANCE

17.0 Introduction

The GE-Hitachi Nuclear Energy (GEH) quality assurance program (QAP) used for the economic simplified boiling-water reactor (ESBWR) is based on the standard GEH QAP documented in topical report (TR) NEDO-11209-04A, Revision 8, "GE Nuclear Energy Quality Assurance Program Description," which was approved by the U.S. Nuclear Regulatory Commission (NRC) by letter dated March 31, 1989. The ESBWR design control document (DCD) Tier 2, Revision 9, Section 17.0, provides an overview of the implementation of the GEH QAP and states that the GEH QAP complies with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, "Domestic Licensing of Production and Utilization Facilities," Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants"; the implementing American National Standards Institute(ANSI)/American Society of Mechanical Engineers (ASME) N45.2 series daughter standards, ASME Nuclear QA (NQA)-1-1983 and NQA-1a-1983; and the regulatory guides (RGs) cited in NEDO-11209-04A. DCD Tier 2, Revision 9, Section 17.0, states that the GEH ESBWR work is controlled through NEDO-33181, Revision 2, "NP-2010 COL Demonstration Project Quality Assurance Plan," issued July 2006. NEDO-33181 describes the quality assurance (QA) plan scope, which GEH, as supplier for ESBWR engineering services, is implementing.

The staff inspected the implementation of the GEH QAP for the ESBWR activities as part of its review of DCD Tier 2, Revision 9, Section 17.0. The staff performed these inspections in November 2005, "NRC Inspection Report 05200010/2005-201 and Notice of Nonconformance" (ML053560155); April 2006 "NRC Inspection Report 05200010/2006-201 and Notice of Nonconformance" (ML061590328); and December 2006 "NRC Inspection Report for General Electric Nuclear Energy (GENE) General economic and simplified boiling-water reactor (ESBWR) Quality Assurance Implementation Follow-up Inspection" (ML070100142). As part of the November 2005 inspection, the staff identified unresolved item (URI) 05200010-2005-201-01, which required a description (given in DCD Tier 2, Section 17.0), of the basis of the ESBWR QAP and how GEH and its various domestic and international ESBWR team participants will implement the program. In addition, in URI 05200010-2005-201-02, the staff requested information about the activities associated with the transition from the simplified boiling-water reactor (SBWR) to the ESBWR design, particularly as it relates to the qualification test program activities performed for the SBWR design certification, which are now being used to support the ESBWR design certification application.

During the December 2006 inspection, the staff reviewed Section 17.0 of Chapter 17 of the ESBWR DCD Tier 2, Revision 2, and verified that Section 17.0 adequately addresses the transition from the SBWR to ESBWR design and the basis of the GEH QAP. Section 17.0 describes the evolution of the ESBWR design as it relates to the SBWR test programs conducted at international supplier test facilities such as GIRAFFE, PANTHERS, and PANDA. Additionally, Section 17.0 states that NEDC-33260, Revision 1, "NP-2010 COL Demonstration Project, SQAR—ESBWR QA Requirements for Procurement of Engineering Services and Equipment," issued July 2006, describes the relationship, responsibilities, and requirements for the quality programs of suppliers and subtier suppliers. The staff verified that NEDC-33260 includes the appropriate NQA-1-1983 references and closed URI 05200010-2005-201-01. Section 21.7 of this report discusses the resolution of URI 05200010-2005-201-02.

17.1 Quality Assurance During Design

17.1.1 Regulatory Criteria

The ESBWR DCD Tier 2, Revision 9, Section 17.1, provides a description of the GEH QAP, as documented in NEDO-11209-04A, as required by the following regulations:

- 10 CFR Part 50, Appendix B, establishes the QA requirements for the design, construction, and operation of structures, systems, and components (SSCs) that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public. The pertinent requirements of 10 CFR Part 50, Appendix B, apply to all activities affecting the safety-related functions of those SSCs.
- 10 CFR 52.47(a)(19) requires “a description of the quality assurance program applied to the design of the structures, systems, and components of the facility. 10 CFR Part 50, Appendix B, ‘Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,’ sets forth the requirements for quality assurance programs for nuclear power plants. The description of the quality assurance program for a nuclear power plant shall include a discussion of how the applicable requirements of 10 CFR Part 50, Appendix B were satisfied.”
- 10 CFR 50.34(a)(7) requires that the safety analysis report (SAR) include a description of the QAP to be applied to the design, fabrication, construction, and testing of SSCs of a facility. The description of the QAP for a nuclear power plant shall include a discussion of how the program will satisfy the applicable requirements of 10 CFR Part 50, Appendix B.

The NRC used 10 CFR Part 50, Appendix B, the implementing ANSI/ASME N45.2 series daughter standards and the applicable RGs to evaluate DCD Tier 2, Revision 9, Section 17.1.

17.1.2 Summary of Technical Information

The ESBWR DCD Tier 2, Revision 9, Section 17.1, describes the QAP used by GEH for the ESBWR. It is based on the standard GEH QAP, documented in TR NEDO-11209-04A, Revision 8, which the NRC approved by letter dated March 31, 1989.

17.1.3 Staff Evaluation

The staff reviewed the QAP information provided in DCD Section 17.1. Based on this review, the staff issued request for additional information (RAI) 17.1-1 requesting the applicant to provide further clarification as stated below:

DCD Tier 2, Revision 1, Section 17.1 is titled “Quality Assurance During Design and Construction,” and Section 17.2 is titled “Quality Assurance During the Operations Phase.” Based on the staff’s review, Section 17.1 applies only to GEH QA during the design phase and not to construction. This is supported by the statement in Section 17.2 that “QA responsibilities during the plant construction and operations phases are combined license (COL) holder scope.” Provide an introductory paragraph in DCD Tier 2, Section 17.1, which specifically states section applicability, and consider revising the title of DCD Tier 2, Section 17.1, to be more representative of the section.

In response, GEH revised the title of Section 17.1 to “Quality Assurance During Design” and provided an introductory paragraph stating that Section 17.1 is applicable to the ESBWR design activities supporting the standard design certification. These clarifications resolve RAI 17.1-1.

The staff performed several inspections to verify implementation by GEH of the QAP for the ESBWR design certification. The staff conducted inspections in November 2005, April 2006, and December 2006, at GEH facilities in Wilmington, NC. The following reports document the results of these inspections.

NRC Inspection Report (IR) 05200010/2005-201, dated January 11, 2006, documents the November 2005 inspection. During this inspection, the staff found that the implementation of the GEH QAP failed to meet certain NRC requirements and cited five nonconformances and two URIs. Specifically, the staff found that GEH had not adequately implemented the ESBWR design control process as required by the GEH QAP. GEH did not document the revised completion date for the ESBWR DCD verification when the schedule was not met and did not maintain and update the work plan and detailed schedule for the ESBWR program. GEH did not perform the corrective action request (CAR) acceptance reviews within the required 30-day period and did not document and complete the required corrective and preventive actions identification and the response and closure activities associated with several ESBWR CARs. GEH responded to IR 05200010/2005-201 by letter dated February 9, 2006, and provided corrective and preventive actions for the cited nonconformances. Sections 17.0 and 21.7 of this report discuss the resolution of the URIs.

NRC IR 05200010/2006-201, dated June 14, 2006, documents the April 2006 inspection. During this inspection, the staff reviewed the corrective and preventive actions documented in the GEH letter dated February 9, 2006, and closed the five previously identified nonconformances. The staff also discovered two additional nonconformances with NRC requirements. Specifically, the staff found that the GEH corrective action processes had not been effective in addressing and correcting the root causes of nonconformances. GEH did not adequately implement the requirements to process and complete corrective actions in a timely manner in accordance with its QAP. In addition, the staff found that several ESBWR project documents, including certain DCD sections, referenced editions of the ASME NQA-1 standard that are not consistent with DCD Chapter 17 QAP commitments. In a letter dated July 21, 2006, GEH responded to IR 05200010/2006-201 and provided corrective and preventive actions for the cited nonconformances.

NRC IR 05200010/2006-202, dated January 19, 2007, documents the December 2006 inspection. During this follow-up inspection, the staff reviewed the corrective and preventive actions documented in the GEH letter dated July 21, 2006, and closed the two previously identified nonconformances. In addition, GEH provided supplemental information regarding the two URIs identified in the November 2005 inspection. The staff reviewed the supplemental documentation, as discussed in Sections 17.0 and 21.7 of this report, and considers these URIs closed.

17.1.4 Conclusion

On the basis of its review of the applicable information in DCD Tier 2, Revision 9, Section 17.1, and the QA implementation inspections performed at GEH facilities in Wilmington, NC, the staff finds that GEH has implemented the ESBWR QAP, consistent with the requirements of GEH TR NEDO-11209-04A, Revision 8. Therefore, the staff concludes that DCD Tier 2, Revision 9, Section 17.1, meets the requirements of 10 CFR 50.34(a)(7) and 10 CFR Part 50, Appendix B.

17.2 Quality Assurance During Construction and Operations

The staff reviewed the QAP information provided in DCD Tier 2, Revision 1, Section 17.2. Based on this review, the staff issued RAI 17.2-1 requesting the applicant to provide further clarification as stated below:

DCD Tier 2, Revision 1, Section 17.2, briefly states that the COL applicant is responsible for the QA activities during construction and operating phases. The COL applicant could be responsible for the design phase, along with procurement, fabrication, installation, construction, and testing of SSCs. Provide an introductory paragraph in Section 17.2 that accounts for the COL applicant's QA responsibilities in all phases (design, construction, and operation) and consider a more representative section title.

GEH responded to the staff's RAI, revised the title of Section 17.2 to "Quality Assurance During Construction and Operations," and provided an introductory paragraph stating that the COL applicant is responsible for QA during construction and operations and for design activities necessary to adapt the certified standard plant design to the specific plant implementation. These clarifications resolve RAI 17.2-1. The staff agrees that the QA activities associated with construction and operations, including site-specific design activities, are the COL applicant's responsibility. These are addressed in DCD Tier 2, Revision 9 COL Information Items 17.2-1-A, QA Program for the Construction and Operations Phases, and 17.2-2-A, QA Program for Design Activities. COL information items identify the COL applicant activities that must be performed during the COL application phase.

17.3 Quality Assurance Program Document

DCD Tier 2, Revision 9, Section 17.3, states that the QA program document for the overall project is the COL applicant's responsibility. The staff agrees with this statement. This is COL Information Item 17.3-1-A, Quality Assurance Program Document.

17.4 Reliability Assurance Program During Design Phase

DCD Tier 2, Revision 9, Section 17.4, addresses the Commission's direction for the reliability assurance program (RAP) provided in the staff requirements memorandum (SRM) for "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs (SECY-94-084)" dated June 28, 1995. The guidance for RAP is presented in Item E, "Reliability Assurance Program," of SECY-95-132, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs (SECY-94-084)," dated May 22, 1995, and in U.S. Nuclear Regulatory Commission (NRC), NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants (LWR Edition)," (SRP) March 2007, Section 17.4. The purpose of the RAP is to provide reasonable assurance of the following:

- A reactor is designed, constructed, and operated consistent with the assumptions and risk insights for the SSCs in the scope of the RAP.
- These SSCs do not degrade to an unacceptable level of reliability, availability, or condition during plant operations.
- The frequency of transients that challenge these SSCs is minimized.

- These SSCs function reliably when challenged.

The purpose of the RAP can be achieved by implementing the program in two stages. The first stage applies to reliability assurance activities that occur before the initial fuel load and is referred to as the design reliability assurance program (D-RAP). The staff verifies the D-RAP during the design certification phase through the staff's safety evaluation (SE) review process. The staff verifies implementation of the D-RAP by the COL Licensee through the inspections, tests, analyses, and acceptance criteria (ITAAC) process, as well as inspections and audits during detailed design and construction before initial fuel load.

The second stage applies to reliability assurance activities conducted during the operations phase of the plant's life cycle. These activities are implemented under operational programs specified in DCD Tier 2, Revision 9, Section 13.4. At issuance of a COL by the NRC, operational programs may become license conditions that are implemented by the licensee throughout the life of the plant. The NRC verifies implementation of these operational programs using inspections and audits for the duration of the license.

17.4.1 Regulatory Basis

DCD Tier 2, Revision 9, Section 17.4, describes the RAP for the design phase, as prescribed by the Commission policy and regulatory provisions below:

- Commission policy contained in the SRM for SECY-95-132, Item E, requires a RAP codified by incorporation within the design-specific rulemaking for a design certification applicant. Meeting this requirement provides evidence that: (1) the reactor will be designed, constructed, and operated in a manner that is consistent with the assumptions and risk insights for these risk-significant SSCs, (2) the risk-significant SSCs will not degrade to an unacceptable level of performance or condition during plant operations, (3) the frequency of transients that challenge SSCs will be minimized, and (4) these SSCs will function reliably when challenged. The RAP becomes part of a COL application that references a certified design. In accordance with Commission policy documented in the SRM for SECY-95-132, the ITAAC process will verify the RAP for the design stage.
- 10 CFR 52.47(b)(1) states that a design certification application must contain proposed ITAAC that are necessary and sufficient to provide reasonable assurance that, if the inspections, tests, and analyses are performed and the acceptance criteria are met, a facility that incorporates the design certification has been constructed and will be operated in conformity with the design certification, the provisions of the Atomic Energy Act, and the NRC's regulations.
- SRP Section 17.4 provides review guidance for the RAP. The staff bases its evaluation of the ESBWR RAP on the Commission policy contained in the SRM for SECY-95-132 and the guidance contained in SRP Section 17.4. The staff used the 1996 version of SRP Section 17.4 to perform its review. In comparing the 1996 version of SRP Section 17.4 with the 2007 version, the staff found that the 2007 version contains the following additional requirements or clarifications of existing requirements beyond those identified in the 1996 version:
 - Clarification of the acceptance criteria for essential elements of the D-RAP
 - Clarification of the acceptance criteria for expert panel qualifications
 - Identification of acceptance criteria for ITAAC for D-RAP

Though these items were not included in the 1996 SRP version used by the staff, the staff did address these items. Section 17.4.3 of this safety evaluation report (SER, here after referred to as this report) describes their disposition. Therefore, the staff concludes that the version of the SRP used, in combination with the additional review performed by the staff, is adequate for this review.

17.4.2 Summary of Application

DCD Tier 2, Revision 9, Section 17.4, describes the following: the scope, purpose, and objectives of the D-RAP; the organizations of GEH that are responsible for the D-RAP (i.e., the essential elements of the D-RAP); SSC identification and prioritization; design considerations; the process of defining failure modes; operational reliability assurance activities; the owner/operator's RAP; a sample case for D-RAP implementation; and COL information items needed for implementing the RAP. GEH also provides the following documents that, together with DCD Tier 2, Revision 9, Section 17.4, form the basis of the ESBWR D-RAP and the D-RAP ITAAC:

- Licensing Topical Report (LTR) NEDO-33289, Revision 2, "ESBWR Reliability Assurance Program," issued September 2008. LTR NEDO-33289 presents the plans for, and the constituents of, the generic RAP required by the SRP as part of the ESBWR design certification.
- ESBWR DCD Tier 1, Revision 9, Section 3.6, "Design Reliability Assurance Program." This section of the DCD provides the D-RAP ITAAC.
- LTR NEDO-33411, Revision 2, "Risk Significance of Structures, Systems and Components for the Design Phase of the ESBWR," issued February 2010. LTR NEDO-33411 describes the methodology for evaluating, identifying, and prioritizing SSCs according to their degree of risk significance, using a combination of probabilistic, deterministic, or other methods of analysis. This report also provides a list of risk-significant SSCs.

DCD Tier 2, Revision 9, Section 17.4.13 and the associated Section 17.4.1 provide COL Information Items 17.4-1-A, Identifying Site-Specific SSCs within the Scope of the RAP, and 17.4-2-A, Operation Reliability Assurance Activities. COL Information Item 17.4-1-A identifies the COL applicant activities that must be performed during the COL application phase in support of D-RAP. COL Information Item 17.4-2-A identifies the COL applicant activities that must be performed during the COL application phase in support of the RAP during the operations phase.

17.4.3 Technical Evaluation

DCD Tier 2, Revision 9, Section 17.4, together with LTRs NEDO-33289, Revision 2, and NEDO-33411, Revision 2, form the basis of the RAP for the ESBWR. Elements of the RAP for the ESBWR include the following:

- Scope, purpose, and objectives of the RAP during the design phase
- Essential elements of the RAP during the design phase
- SSC identification and prioritization
- Dominant failure mode determination
- RAP implementation during the design phase
- RAP implementation during the operations phase
- COL information items

The staff reviewed the documents that form the basis of the ESBWR RAP to ensure that the RAP meets the guidance in the Commission's policy contained in Item E of the SRM on SECY-95-132 and SRP Section 17.4. As discussed in Section 17.4.1 of this report, the staff used the 1996 version of SRP Section 17.4 to perform its review. The staff compared the 1996 version of SRP Section 17.4 with the 2007 version of SRP Section 17.4 and found that the 2007 version contains additional requirements or clarifications of existing requirements beyond those identified in the 1996 version. Though these items were not included in the SRP version used, the staff did evaluate these items. The remainder of this section describes the disposition of these items. Therefore, the staff concludes that the version of the SRP used, in combination with the additional review performed by the staff, is adequate for this review.

As with the certification of previous advanced reactor designs (e.g., the AP1000 and advanced boiling-water reactor [ABWR] designs), the staff's review of the ESBWR RAP included the issuance of RAs to the applicant, followed by the evaluation of the applicant's responses to the RAs. The staff issued 55 RAs to the applicant during its review of the ESBWR RAP. These RAs covered all aspects of the RAP. The following describes the staff's technical evaluation of the information contained in DCD Tier 2, Revision 9, Section 17.4 and LTRs NEDO-33289 and NEDO-33411.

17.4.3.1 Scope, Purpose, and Objectives of the D-RAP

The NRC reviewed GEH's description of the RAP, provided in DCD Tier 2, Sections 17.4.1, 17.4.2, 17.4.3, and 17.4.4. The staff followed Item E of the Commission policy contained in the SRM for SECY-95-132 and the 1996 version of SRP Section 17.4 to ensure that this subject review area meets the guidance contained in these documents. The staff compared the SRP version used during the review with the 2007 version of SRP Section 17.4. For this subject review area, the 2007 version did not include any requirements, generic issues, bulletins, generic letters, or technically significant acceptance criteria beyond those identified in the version used by the staff. Therefore, the staff concludes that the 1996 version of SRP Section 17.4 is adequate for this review.

The SSCs in the scope of the ESBWR D-RAP include: (1) all RTNSS SSCs identified under ESBWR DCD Tier 2, Section 19A, and (2) all risk-significant SSCs identified under NEDO-33411. These SSCs provide defense-in-depth or result in significant improvements in the probabilistic risk assessment (PRA) evaluations. The purpose of the ESBWR D-RAP is to ensure that plant safety, as estimated by the PRA, is maintained during the detailed design and construction phases. The objective of the ESBWR D-RAP is to ensure that the reactor is designed and constructed consistent with the key assumptions and risk insights for the SSCs within the scope of the D-RAP. The PRA and other sources identify the within-scope SSCs. The D-RAP also identifies key assumptions related to operation, maintenance, and monitoring activities that the owner/operator should consider in implementing operational reliability assurance activities, to ensure that, when challenged, such SSCs function reliably throughout the plant's life with the reliability assumed in the PRA. Within-scope SSCs are subject to the QA activities established under the provisions of SRP Section 17.5.

Based on the discussion in this section, the staff concludes that GEH has adequately described the scope, purpose, and objectives of the D-RAP and that the DCD meets the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, this subject review area is acceptable.

17.4.3.2 GEH Organizations Responsible for the D-RAP

The staff reviewed the description of the GEH organizations that are responsible for developing, coordinating, and implementing the D-RAP described in DCD Tier 2, Revision 9, Section 17.4.5. The staff performed this review in accordance with Commission policy contained in Item E of the SRM for SECY-95-132 and the 1996 version of SRP, Section 17.4 to ensure that this subject area meets the guidance contained in these documents. For this review, the staff compared the SRP version used during the review with the 2007 version of SRP Section 17.4. The 2007 version clarified the acceptance criteria for the essential elements of D-RAP (i.e., organization, design control, procedures and instructions, corrective action, records, and audits). The version used by the staff did not include these clarified acceptance criteria; however, the staff did address this item as described in the following discussion. Therefore, the staff concludes that the version of the SRP used, in combination with the additional review performed by the staff, is adequate for this review.

Based on its review, the staff prepared the following RAIs for areas where it needed additional information to complete its review:

RAI 17.4-4 discussed that in DCD Tier 2, Revision 0, Section 17.4.5, GEH did not describe the essential elements for the D-RAP. The staff interpreted the essential elements, as described in the Commission policy contained in the SRM for SECY-95-132, Item E, to mean the application of the following essential elements to the D-RAP:

- Organization
- Design control
- Procedures and instructions
- Corrective action
- Records
- Audits

The staff asked GEH to ensure that the D-RAP provided an overview of the process for implementing these essential elements.

RAI 17.4-5 discussed that in DCD Tier 2, Revision 0, Section 17.4.5, GEH did not provide details of its D-RAP organizational structure. The RAI asked GEH to include a discussion of the interface controls among the PRA, the D-RAP, and design organizations. GEH was asked to also consider developing an expert panel within the GEH organization with a charter that includes determining the list of SSCs in the scope of the D-RAP. The members of the expert panel should be subject matter experts with experience in systems, operations, and maintenance. GEH should discuss the PRA organization within the design organization. GEH should also develop an internal procedure describing how the organization will implement the D-RAP.

RAI 17.4-6 discussed that in DCD Tier 2, Revision 0, Section 17.4.5, GEH did not discuss the measures that will be established to identify and control the design interfaces and to coordinate the participating design organizations. Since the ESBWR full-scope PRA is not complete and is subject to change, the staff asked GEH to describe the process used to control changes in the PRA that could affect the list of SSCs in the scope of the D-RAP. In addition, GEH should describe how the design control process provides a feedback mechanism for notifying the PRA organization of changes in the design of within-scope SSCs that could affect the PRA. GEH

should also describe its configuration control process for maintaining the list of SSCs within the scope of the D-RAP, similar to the control of a quality list.

In response to RAIs 17.4-4, 17.4-5, and 17.4-6, GEH revised DCD Tier 2, Section 17.4.5 to state that the ESBWR engineering organization is responsible for the design analysis and PRA engineering necessary to support the development of the D-RAP. The ESBWR PRA personnel participate in the design change control process, which includes providing inputs related to the D-RAP to the design process. GEH applies ESBWR engineering design procedural controls to the D-RAP. Specific procedures provide guidance on the design process, control of design changes, and storage and retrieval controls. In addition, the procedure for design change control defines the process for evaluating design changes in engineering controlled documents to ensure that the total effect is considered before a change is approved and that the affected documents are identified and changed accordingly. The list of SSCs within the scope of the D-RAP is maintained in accordance with NEDO-33289, Revision 2, "ESBWR Reliability Assurance Program Plan." The staff finds that the changes documented in DCD Tier 2, Revision 9, Section 17.4.5, adequately describe the interfaces between the various GEH organizations responsible for the D-RAP. The staff concludes that DCD Tier 2, Revision 9, Section 17.4.5, meets the requirements in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, the concerns associated with RAIs 17.4-4, 17.4-5, and 17.4-6 are resolved.

The NRC issued the following additional RAIs to GEH. In RAI 17.4-7, the staff asked GEH to develop an internal procedure for implementing the D-RAP. The procedure should also describe interface controls among all of the organizations involved in the D-RAP. The procedure should describe the process for identifying and prioritizing the list of SSCs in the scope of the D-RAP. In RAI 17.4-8, the staff asked GEH to describe, in detail, the corrective action process applied to within-scope SSCs. In RAI 17.4-9, the staff asked GEH to describe, in detail, the controls for records of activities involving within-scope SSCs. In RAI 17.4-10, the staff asked GEH to describe, in detail, the audit plans for conducting QA audits of D-RAP activities.

In response, GEH submitted NEDO-33289 and added it to the reference listing in DCD Tier 2, Section 17.4.14. The staff finds that NEDO-33289, Revision 2, and DCD Tier 2, Revision 2, Sections 17.4.5 and 17.4.7, contain sufficient details about the interfaces among the GEH ESBWR engineering organization, the PRA organization, and the design change control process. GEH also sufficiently addressed the essential elements of the D-RAP (i.e., organization, design control, procedures and instructions, corrective action, records, and audit plans) in NEDO-33289, Revision 2, and DCD Tier 2, Revision 2, Section 17.4. Therefore, RAIs 17.4-7 through 17.4-10 are resolved.

RAI 17.4-51 discussed that RG 1.206, "Combined License Applications for Nuclear Power Plants," issued April 2007, Section C.III.1, Chapter 17, Subsection C.I.17.4.4 (page C.III.1-180), states that the COL applicant should describe, in the final safety analysis report, the essential elements (organization, design control, procedures and instructions, records, corrective action, and audit plans) for developing and implementing the D-RAP in accordance with the provisions in SRP Section 17.4. While the essential elements for developing and implementing the D-RAP that are applied by a COL applicant referencing the ESBWR DCD may be similar to those described in Section 17.4.5 of the ESBWR DCD, the COL applicant should impose its own essential elements for developing and implementing the D-RAP. The staff requested that GEH add a COL information item to include the description of the essential elements for developing and implementing the D-RAP that the COL applicant will apply before the initial fuel load.

In response to RAI 17.4-51, GEH stated that DCD COL Information Item 17.4-1-A will also require the COL applicant to provide a description of the essential elements for developing and implementing the D-RAP (i.e., organization, design control, procedures and instructions, records, corrective action, and audit plans) that the applicant will apply before the initial fuel load.

The staff finds that the GEH response to RAI 17.4-51 sufficiently addresses the concerns associated with this RAI. The staff confirmed that COL Information Item 17.4-1-A of DCD Tier 2, Revision 6, was revised accordingly. Based on the above discussion, RAI 17.4-51 is resolved. The NRC verifies implementation of the essential elements of D-RAP by the COL Licensee through inspections and audits during detailed design and construction before initial fuel load.

Based on the preceding, the staff concludes that the information regarding the essential elements of the D-RAP described in LTR NEDO-33289, Revision 2, and DCD Tier 2, Revision 9, Sections 17.4.5 and 17.4.7, meet the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, this subject review area is acceptable.

17.4.3.3 *SSC Identification and Prioritization*

The staff reviewed the identification and prioritization of SSCs in the scope of the D-RAP, which are described in DCD Tier 2, Section 17.4.6. As discussed in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4, the design certification applicant should identify the SSCs in the scope of the D-RAP. The staff performed this review in accordance with Item E of the Commission policy contained in the SRM for SECY-95-132 and the 1996 version of SRP Section 17.4 to ensure that this subject review area meets the guidance contained in these documents. The staff compared the SRP version used during its review with the 2007 version of SRP Section 17.4. For this subject review area, the 2007 version did not include any requirements, generic issues, bulletins, generic letters, or technically significant acceptance criteria beyond those identified in the version used by the staff. Therefore, the staff concludes that the 1996 version of SRP Section 17.4 is adequate for this review.

The following presents the staff's findings from the review of this subject area. In Revision 0 through Revision 4 of DCD Tier 2, Section 17.4.6, GEH did not provide any information concerning the list of SSCs in the scope of the D-RAP. Therefore, the staff issued RAI 17.4-1, in which the staff requested that GEH provide the list of SSCs in the scope of the D-RAP, including its evaluation methodology.

In response, GEH stated that the process of developing and maintaining the list of risk-significant SSCs is described in NEDO-33289 and in a design specification report (later which this report became designated as NEDO-33411, "Risk Significance of Structures, Systems and Components for the Design Phase of the ESBWR"). GEH also stated that it would identify a comprehensive list of risk-significant SSCs at a later phase of D-RAP development. In RAI 17.4-1 S01, the staff requested that GEH submit this design specification report and reference this document in DCD Tier 2, Section 17.4, so that the staff can complete its review of the ESBWR D-RAP. The staff tracked RAI 17.4-1 as an open item in the SER with open items.

In response, GEH stated that the list of risk-significant SSCs for the ESBWR design certification application will be maintained in NEDO-33411. GEH has submitted NEDO-33411 to the NRC.

The staff verified that DCD Tier 2, Revision 9, Section 17.4, referenced NEDO-33411, Revision 2, and that NEDO-33411 provides a list of risk-significant SSCs, including the methodology used to identify them. The SSCs in the scope of the D-RAP include: (1) all RTNSS SSCs identified in ESBWR DCD Tier 2, Revision 9, Section 19A, and (2) all risk-significant SSCs identified in NEDO-33411, Revision 2. Section 17.4.3.9 of this report contains the staff's SE of NEDO-33411. Based on the above discussion, RAI 17.4-1 and the associated open item are resolved.

RAI 17.4-12 discussed that the staff determined that GEH should add the following COL information item to DCD Section 17.4.13:

The COL applicant or holder will establish PRA importance measures, the expert panel process, and other deterministic methods to determine the site-specific list of SSCs under the scope of the D-RAP.

In response, GEH stated that it would add a COL information item to the next revision of DCD Tier 2, Section 17.4. The staff confirmed that GEH added, in COL Information Item 17.4-2-A of DCD Tier 2, Revision 6, the following COL requirement: "Establish PRA importance measures, the expert panel process, and deterministic methods to determine the site-specific list of SSCs under the scope of the D-RAP." Therefore, RAI 17.4-12 is resolved. The NRC verifies the identification of these SSCs by the COL Licensee through the ITAAC process, as well as inspections and audits during detailed design and construction before initial fuel load.

RAI 17.4-50 discussed that DCD Tier 2, Revision 5, Section 17.4.1, stated that the COL holder will establish PRA importance measures, the expert panel process, and deterministic methods to determine the site-specific list of SSCs in the scope of the D-RAP. Per the Commission policy contained in the SRM for SECY-95-132, Item E, a COL applicant referencing the ESBWR design will need to address this same COL information item. The staff requested that GEH add a COL applicant information item to identify the site-specific SSCs in the scope of the D-RAP.

In response, GEH stated that it would add this COL information item to the next revision of DCD Tier 2, Section 17.4. The staff confirmed that GEH added COL Information Item 17.4-1-A to DCD Tier 2, Revision 6, to identify site-specific SSCs in the scope of the D-RAP. Therefore, RAI 17.4-50 is resolved. The NRC verifies the identification of these SSCs by the COL applicant through the agency's SE review process.

In RAI 17.4-3, the staff requested additional information in DCD Tier 2, Section 17.4 concerning the use of PRA importance measures (i.e., Fussell-Vesely [FV] importance greater than one percent and risk achievement worth [RAW] greater than five). The staff requested GEH to add PRA importance measure threshold values to DCD Section 17.4.6.

In response, GEH stated that PRA Level I basic events representing component failures are identified as risk-significant if their importance values for RAW are greater than or equal to 5.0 or, for FV greater than or equal to 0.01.

The staff finds that this change to DCD Tier 2, Revision 4, Section 17.4.6, resolves the concern in RAI 17.4-3. Section 17.4.3.9 of this report contains the staff's SE of NEDO-33411, which provides the detailed methodology used to evaluate, identify, and prioritize the list of risk-significant SSCs.

Based on the discussion in this section, the staff concludes that DCD Tier 2, Revision 9, Section 17.4.6, adequately describes the identification and prioritization of risk-significant SSCs in the scope of the D-RAP and references NEDO-33411, Revision 2, which provides the list of risk-significant SSCs and describes the methodology for evaluating and identifying them. Therefore, DCD Tier 2, Revision 9, Section 17.4.6 is acceptable.

17.4.3.4 Design Considerations

The NRC reviewed DCD Tier 2, Section 17.4.7, which describes the evaluation of the reliability of within-scope SSCs that will be performed at the detailed design stage by appropriate design reviews and reliability analyses. The staff performed this review in accordance with Item E of the Commission policy contained in the SRM for SECY-95-132 to ensure that this subject review area meets that guidance. Based on its review, the staff identified the following area where it needed additional information to complete its review:

RAI 17.4-55 discussed that all within-scope SSCs should be subject to the QA controls that are described in the QAP description submitted by the applicants for a design certification or COL, in accordance with the provisions in the 2007 version of SRP, Section 17.5. For example, the nonsafety-related within-scope SSCs should be subject to QA controls, in accordance with the provisions of Section V, "Non-Safety-Related SSC Quality Controls," in SRP, Section 17.5. However, it was not clear from DCD Section 17.4 that the within-scope SSCs are subject to these QA controls. The staff requested that GEH clarify, in DCD Section 17.4 that all within-scope SSCs are subject to these QA controls.

In response, GEH referred to DCD Tier 2, Section 17.1.22, which states that nonsafety-related SSCs that perform safety-significant functions have QA requirements commensurate with the importance of the item's function and that DCD Tier 2, Table 3.2-1, identifies these SSCs. Notes 5(h) and 5(i) in Table 3.2-1 explain the basis for items designated as Quality Class S for nonsafety-related RTNSS functions. However, Table 3.2-1 does not consider nonsafety-related SSCs that are risk-significant but not designated as RTNSS. Therefore, to address the staff's request, GEH revised ESBWR DCD Tier 2, Table 3.2-1 to clarify that the nonsafety-related SSCs that are risk-significant but not designated as RTNSS are assigned Quality Class S.

The staff finds that the GEH response to RAI 17.4-55 sufficiently addresses the concerns associated with this RAI. All within-scope SSCs are subject to the appropriate QA activities, in accordance with the provisions in Section 17.5 of the SRP. The staff confirmed that Table 3.2-1 of DCD Tier 2, Revision 7, was revised accordingly (also refer to the Section 3.2, of this report). Based on the above discussion, RAI 17.4-55 is resolved.

The staff finds that GEH adequately discussed design considerations in DCD Tier 2, Revision 9, Section 17.4.7. The staff finds that the design considerations included in DCD Tier 2, Revision 9, Section 17.4.7, meet the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and, therefore, are acceptable.

17.4.3.5 Determining Dominant Failure Modes

The staff reviewed the process for determining the dominant failure modes of within-scope SSCs, which is described in DCD Tier 2, Section 17.4.8, in accordance with Item E of the Commission policy contained in the SRM for SECY-95-132 and the 1996 version of SRP Section 17.4, to ensure that this subject review area meets the guidance contained in these documents. The staff compared the SRP version used during its review with the 2007 version

of SRP Section 17.4. For this subject review area, the 2007 version did not include any requirements, generic issues, bulletins, generic letters, or technically significant acceptance criteria beyond those identified in the version used by the staff. Therefore, the staff concludes that the 1996 version of SRP Section 17.4 is adequate for this review.

As discussed in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4, the application should describe an acceptable process to determine dominant failure modes that considers industry experience, analytical models, and applicable requirements.

The following provides the staff's findings from the review of this subject area. The determination of dominant failure modes of within-scope SSCs includes the evaluation of historical information, analytical models, and existing requirements. A significant historical record exists for many boiling-water reactor (BWR) systems and components, and that record can be evaluated. An analytical approach is necessary for those SSCs that do not have an adequate historical basis to identify critical failure modes. Inputs may include a PRA importance analysis, a root-cause analysis, an analysis of failure modes and effects, and a review of operating experience. In addition, equipment performance information, including vendor manuals, ASME Section XI technical specifications (TS), RTNNS, and other regulatory requirements are reviewed to identify important safety functions. Based on its review, the staff identified areas where it needed additional information to complete its review of the process for determining dominant failure modes.

RAI 17.4-11 discussed that in DCD Tier 2, Revision 0, Section 17.4.8, GEH stated, "Many boiling-water reactor (BWR) systems and components have compiled a significant historical record, so an evaluation of that record is performed." The staff found that GEH had not used an evaluation of the historical records for BWR systems and components to develop the D-RAP. The staff asked GEH to clarify the source of information used to define dominant failure modes, as described in DCD Tier 2, Section 17.4.8.

In addition, RAI 17.4-48 discussed that DCD Tier 2, Revision 5, Section 17.4.8 described a process for defining dominant failure modes of within-scope SSCs. However, it was not clear whether the COL applicant or the COL holder was responsible for determining the dominant failure modes of these SSCs. The staff requested that GEH clarify, in DCD Tier 2, Section 17.4, whether the COL applicant or the COL holder is responsible for determining the dominant failure modes of these SSCs and include this as a COL information item in DCD Tier 2, Section 17.4.13.

In response to RAI 17.4-11, GEH stated that it had not evaluated the historical records for BWR systems and components, but these records would be evaluated in the COL application phase of the D-RAP, in accordance with NEDO-33289. The staff confirmed that GEH added the following requirement as COL Information Item 17.4-2-A to DCD Tier 2, Revision 5 Section 17.4.1:

Establish a reliability database using historical data on equipment performance as available. The compilation and reduction of this data provides the plant with a source of component reliability information. Data used in PRA fault-tree analyses may also be a viable initial source.

In response to RAI 17.4-48, GEH stated, in DCD Tier 2, Section 17.4.1, that the dominant failure modes of within-scope SSCs are addressed by the COL Licensee. The staff confirmed that

GEH added COL Information Item 17.4-2-A to DCD Tier 2, Revision 6, to state the COL requirement for determining the dominant failure modes of within-scope SSCs.

The staff finds that the GEH responses to RAIs 17.4-11 and 17.4-48 sufficiently address the concerns associated with these RAIs. Based on the above discussion, RAIs 17.4-11 and 17.4-48 are resolved.

Based on the discussion in this section, the staff concludes that the process for determining dominant failure modes of within-scope SSCs is adequate and meets the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, this subject review area is acceptable.

17.4.3.6 D-RAP Implementation

The staff reviewed DCD Tier 2, Section 17.4.11. In this section, GEH provided an example of the implementation of the D-RAP using the isolation condenser system (ICS) in Section 17.3.11 of the Simplified Boiling Water Reactor (SBWR) SAR (GE Nuclear Energy, "Application for Design Certification of the Simplified Boiling Water Reactor (SBWR)," Project No. 681, SLK-9289, August 27, 1992). GEH used this example to guide early design work in the ESBWR. The staff performed its review in accordance with Item E of the Commission policy contained in the SRM for SECY-95-132 and the 1996 version of SRP Section 17.4 to ensure that this subject review area meets the guidance contained in these documents. The staff compared the SRP version used during its review with the 2007 version of SRP Section 17.4. For this subject review area, the 2007 version did not include any requirements, generic issues, bulletins, generic letters, or technically significant acceptance criteria beyond those identified in the version used by the staff. Therefore, the staff concludes that the 1996 version of SRP Section 17.4 is adequate for this review.

The following presents the staff's findings from the review of this subject area. The staff requested additional information to complete the review.

RAI 17.4-2 discussed that in DCD Section, Tier 2, Revision 0, 17.4.1, GEH stated, in part, that "included in this explanation of the D-RAP is a descriptive example of how the D-RAP applies to one potentially important system, the Isolation Condenser System (ICS). The ICS example shows how the principles of D-RAP will be applied to the other systems identified by the PRA as being significant with respect to risk." In addition, the staff noted that GEH had incorporated references to design reliability improvements to the ICS in the SBWR SAR, Section 17.3.11. However, GEH withdrew the SBWR application in 1995 and did not include this information from the SBWR application in the ESBWR design certification application. If GEH used the D-RAP to improve the reliability of an ESBWR system, then GEH should provide an example in DCD Tier 2, Section 17.4.11.

In response, GEH described the ICS and the major differences between the ESBWR ICS and the conventional BWR ICS and supplied information about design reliability improvements to the ICS in DCD Tier 2, Section 17.4.11. GEH also included risk information and identified failure modes and maintenance requirements for the ICS. The staff reviewed the revised information in DCD Tier 2, Revision 4, Section 17.4.11, and concludes that this information resolves the concern in RAI 17.4-2.

The staff concludes that the case example provided for D-RAP implementation in DCD Tier 2, Revision 9, Section 17.4.11, is sufficient to meet the guidance in the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4 and, therefore, is acceptable.

17.4.3.7 *Implementation of the Reliability Assurance Process during the Operations Phase*

The staff reviewed the GEH proposed implementation of the reliability assurance process during the operations phase, which is described in DCD Tier 2, Section 17.4.9 and Section 17.4.10 in accordance with Item E of the Commission policy contained in the SRM for SECY-95-132 and the 1996 version of SRP Section 17.4, to ensure that this subject review area meets the guidance contained in these documents. The staff compared the SRP version used during its review with the 2007 version of SRP Section 17.4. For this subject review area, the 2007 version did not include any requirements, generic issues, bulletins, generic letters, or technically significant acceptance criteria beyond those identified in the version used by the staff. Therefore, the staff concludes that the 1996 version of SRP Section 17.4 is adequate for this review.

As discussed in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4, the NRC expects licensees to implement the RAP during the operations phase by integrating into operational programs the reliability assurance activities for within-scope SSCs. With the exception of reliability assurance related to the design and operation of nonsafety-related within-scope SSCs, the objective of the RAP during the operations phase can be accomplished within; (1) the QAP that meets the requirements of 10 CFR Part 50, Appendix B, (2) the maintenance rule program that meets the requirements of 10 CFR 50.65, and (3) the underlying maintenance and surveillance programs. Implementation of the maintenance rule following the guidance contained in RG 1.160, Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," is one acceptable method for crediting the maintenance rule program in the implementation of the RAP during the operations phase, provided that these SSCs are categorized as having high safety significance (HSS).

The following presents the staff's findings from the review of this subject area. The staff identified that it needed additional information to complete its review of this subject.

In RAI 17.4-13, the staff asked, per the discussion of RAP during the operations phase in the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4, that GEH state in DCD Tier 2, Section 17.4.9 whether, and if so, how, the RAP process will be implemented through existing operational programs, including the maintenance and surveillance program(s), the QAP, and the maintenance rule program.

In response, GEH stated that it would revise DCD Tier 2, Section 17.4.9, to state that the operational reliability assurance activities are the responsibility of the COL Licensee and will be implemented through the COL Licensee's maintenance and surveillance programs, the QAP, and the maintenance rule program. In accordance with COL Information Item 17.4-2-A, the COL Licensee will implement these operational reliability assurance activities that meet the objectives of the RAP during the operations phase. The GEH response is sufficient to meet the guidance in the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4 and, therefore, is acceptable. The staff confirmed that DCD Tier 2, Revision 4, Section 17.4.9, was revised accordingly. Therefore, RAI 17.4-13 is resolved.

In RAI 17.4-14, the staff requested that GEH address reliability data from test results collected from TS surveillance tests and other relevant testing and from industry operating experience for both safety-related and RTNSS SSCs, as available. This information can also be obtained from reliability estimates in the ESBWR PRA. GEH should add a reference to these sources for reliability estimates and monitoring information to DCD Tier 2, Section 17.4.9.

In response, GEH stated that it would revise DCD Tier 2, Section 17.4.9, to identify the use of TS surveillance test data and industry operating data for safety-related equipment, when available, as sources for reliability estimates and monitoring information. The GEH response to RAI 17.4-14 was incomplete, in that it did not address RTNSS SSCs and the ESBWR PRA as a source of reliability information, as stated in RAI 17.4-14. Upon reviewing DCD Tier 2, Revision 4, Section 17.4.9, the staff confirmed that GEH added RTNSS SSCs and the reference to ESBWR PRA information and that Section 17.4.9 is otherwise satisfactory. These clarifications resolve RAI 17.4-14.

In RAI 17.4-16, the staff requested the applicant to add the following COL information items related to operational reliability assurance activities to DCD Tier 2, Section 17.4.13 to meet the guidance in the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4:

- The COL applicant is responsible for integrating the objectives of operational reliability assurance activities into the QAP developed to implement 10 CFR Part 50, Appendix B. This program should also address failures of nonsafety-related within-scope SSCs that result from design and operational errors, in accordance with the Commission policy contained in the SRM for SECY-95-132, Item E.
- The COL applicant is responsible for performing the tasks necessary to maintain the reliability of within-scope SSCs. The applicant may cite, for example, cost-effective maintenance enhancements, such as condition monitoring and using condition-directed maintenance, as well as time-directed or planned periodic maintenance.
- The COL applicant's maintenance rule (10 CFR 50.65) program is required to monitor the effectiveness of the COL applicant's maintenance activities needed for operational reliability assurance. As such, it is an important element of the RAP during the operations phase. If the COL applicant proposes to use its maintenance rule program to implement the RAP during the operations phase, the SSCs in the scope of the maintenance rule program that are classified as HSS should encompass all within-scope SSCs.
- In addition to the specific tasks necessary to maintain SSC reliability, the operational reliability assurance activities should include the following:
 - A reliability database contains historical data on equipment performance, as available. The compilation and reduction of these data provide the plant with a source of component reliability information. Data used in PRA fault-tree analyses may also be a viable initial source.
 - Surveillance and testing establish the level of performance or condition being maintained for within-scope SSCs and identify, to the extent possible, declining trends between surveillances, before performance or conditions degrade to unacceptable levels without being detected (or before they fail).

- The maintenance plan describes the nature and frequency of maintenance activities to be performed on plant equipment. The plan includes the selected SSCs identified in the D-RAP.

In response to RAI 17.4-16 and the associated supplemental RAIs, GEH added the following COL requirements to COL Information Item 17.4-2-A in DCD Tier 2, Revision 9, Section 17.4.13:

- Integrate the objectives of operational reliability assurance activities into the QAP, including addressing failures of nonsafety-related risk-significant SSCs in the scope of the D-RAP that result from design and operational errors, in accordance with the Commission policy contained in the SRM for SECY-95-132, Item E.
- Evaluate and maintain the reliability of SSCs as identified in the D-RAP. This includes determining the dominant failure modes of SSCs. The program may cite, for example, reliability analysis, cost-effective maintenance enhancements, such as condition monitoring and using condition-directed maintenance, as well as time-directed or planned periodic maintenance.
- Use the maintenance rule (10 CFR 50.65) program to monitor the effectiveness of maintenance activities needed for operational reliability assurance.
- Consider all SSCs that are in the scope of the D-RAP as HSS within the scope of the maintenance rule program or provide an expert panel justification for any exceptions.

Note: The expert panel, in accordance with common industry practice and guidance in Nuclear Management and Resources Council, Inc. (NUMARC) 93-01, develops the final list of risk-significant SSCs from various inputs, including the PRA risk importance calculations and industry operating experience. It is necessary for the expert panel to include all SSCs that are in the scope of the D-RAP in the HSS category of SSCs within the scope of the maintenance rule. However, risk-importance calculations, plant specifics, and other factors may change the risk significance of certain SSCs in the operational RAP that were previously determined to be risk-significant within the bounds of the D-RAP. Therefore, differences may exist between the D-RAP and operational RAP risk significance that the expert panel should evaluate and justify.

- Establish a reliability database using historical data on equipment performance, as available. The compilation and reduction of these data provide the plant with a source of component reliability information. Data used in PRA fault-tree analyses may also be a viable initial source.
- Use surveillance and testing to establish the level of performance or condition being maintained for SSCs in the scope of the RAP and identify, to the extent possible, declining trends between surveillances before performance or conditions degrade to unacceptable levels without being detected (or before they fail).
- Develop a maintenance plan to describe the nature and frequency of maintenance activities to be performed on plant equipment. The plan includes the selected SSCs identified in the D-RAP.

Subsequently, the applicant proposed that the COL requirements described above should be COL “applicant” information items, and that the COL applicant will provide a description of these operational reliability assurance activities. These activities are implemented under operational programs that have their own milestones, specified in DCD Tier 2, Section 13.4, and some are implemented after fuel load (e.g., inservice testing). Therefore, the staff agrees that COL Information Item 17.4-2-A should be a COL information item in which the COL applicant will describe the operational reliability assurance activities that are consistent with the above requirements. The staff confirmed that GEH had revised Section 17.4.13 and the associated Section 17.4.1 of DCD Tier 2, Revision 6, to incorporate these COL information items. Therefore, RAI 17.4-16 is resolved.

Based on the discussion in this section, the staff concludes that the proposed implementation of the reliability assurance process during the operations phase, which is described in DCD Tier 2, Revision 9, Sections 17.4.9 and 17.4.10, is adequate and meets the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, this subject review area is acceptable.

17.4.3.8 COL Information Items

The staff reviewed the COL information items, which appear in DCD Tier 2, Section 17.4.13 and the associated Section 17.4.1, in accordance with Item E of the Commission policy contained in the SRM for SECY-95-132 and the 1996 version of SRP Section 17.4, to ensure that this subject review area meets the guidance contained in these documents. The staff compared the SRP version used during its review with the 2007 version of SRP Section 17.4. For this subject review area, the 2007 version did not include any requirements, generic issues, bulletins, generic letters, or technically significant acceptance criteria beyond those identified in the version used by the staff. Therefore, the staff concludes that the 1996 version of SRP Section 17.4 is adequate for this review.

In DCD Tier 2, Revision 2, Section 17.4.13, GEH listed only one COL information item related to the RAP during the operations phase. As discussed in the previous sections of this report, the staff found that the following additional COL information items are needed to meet the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. The COL information items for DCD Tier 2, Revision 9, Section 17.4.13, and the associated Section 17.4.1 are as follows:

COL Information Item 17.4-1-A

The COL applicant will identify the site-specific SSCs within the scope of the RAP and describe the quality elements for developing and implementing the D-RAP (that is, organization, design control, procedures and instructions, records, corrective action, and audit plans) that will be applied before the initial fuel load.

COL Information Item 17.4-2-A

The COL applicant will provide a description of operational reliability assurance activities. These activities are consistent with the following requirements:

- Integrate the objectives of operational reliability assurance activities into the QA program, including addressing failures of nonsafety-related, risk-significant SSCs that result from

design and operational errors in accordance with the Commission policy contained in the SRM for SECY-95-132, Item E.

- Establish PRA importance measures, the expert panel process, and deterministic methods to determine the site-specific list of SSCs within the scope of the D-RAP.
- Evaluate and maintain the reliability of SSCs as identified in the D-RAP. This includes determining the dominant failure modes of SSCs. The program may cite, for example, reliability analysis, cost-effective maintenance enhancements, such as condition monitoring and using condition-directed maintenance, as well as time-directed or planned periodic maintenance.
- Use the maintenance rule (10 CFR 50.65) program to monitor the effectiveness of maintenance activities needed for operational reliability assurance.
- Consider all SSCs that are in the scope of the D-RAP as HSS within the scope of the maintenance rule program, or provide expert panel justification for any exceptions.

Note: The expert panel, in accordance with common industry practice and guidance in NUMARC 93-01, develops the final list of risk-significant SSCs from various inputs, including the PRA risk importance calculations and industry operating experience. The expert panel must include all SSCs that are in the scope of the RAP in the HSS category of SSCs within the scope of the maintenance rule. However, risk importance calculations, plant specifics, and other factors may change the risk significance of certain SSCs in the operational RAP that were previously determined to be risk-significant within the bounds of the D-RAP. Therefore, differences may exist between the D-RAP and operational RAP risk significance that the expert panel should evaluate and justify.

- Establish a reliability database using historical data on equipment performance as available. The compilation and reduction of these data provide the plant with a source of component reliability information. Data used in PRA fault-tree analyses may also be a viable initial source.
- Use surveillance and testing to establish the level of performance or condition being maintained for SSCs in the scope of the RAP and identify, to the extent possible, declining trends between surveillances before performance or conditions degrade to unacceptable levels without being detected (or before they fail).
- Develop a maintenance plan to describe the nature and frequency of maintenance activities to be performed on plant equipment. The plan includes the selected SSCs identified in the D-RAP.

As discussed in previous sections of this report, the staff's review of DCD Tier 2, Revision 6, Section 17.4.13 and the associated Section 17.4.1, confirmed that these sections include all necessary COL information items and meet the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, this subject review area is acceptable.

17.4.3.9 Risk Significance of SSCs for the Design Phase of the ESBWR, NEDO-33411

The staff reviewed NEDO-33411, in accordance with Item E of SECY-95-132 and SRP Section 17.4, to ensure that the identification and prioritization of risk-significant SSCs meet the guidance contained in these documents. The objective of NEDO-33411 is to identify the SSCs that are considered risk-significant in the design phase of the ESBWR. NEDO-33411 contains the scope of the assessment, the risk-significance methodology, the expert panel review, and the list of risk-significant SSCs.

17.4.3.9.1 Scope

The staff reviewed the scope of the assessment provided in NEDO-33411, which is described in Section 1.0, "Introduction," of NEDO-33411. As discussed in Item E of the Commission policy contained in the SRM for SECY-95-132 and the 1996 version of SRP Section 17.4, the scope of the assessment should use a combination of probabilistic, deterministic, or other methods of analysis for evaluating, identifying, and prioritizing SSCs according to their degree of risk significance.

The following provides the staff's findings from the review of this subject area. The scope of the assessment described in NEDO-33411 includes the use of probabilistic and deterministic analyses to identify the risk-significant SSCs. These analyses include the use of at-power and shutdown PRAs for internal and external events resulting in core damage and large radiological releases, seismic risk based on the seismic margins analysis (SMA), RTNSS Criteria C and D, risk insights and assumptions, operating experience from currently operating reactors, and expert panels.

Based on the discussion in this section, the staff concludes that the scope of the assessment described in Section 1.0 of NEDO-33411 is adequate and meets the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, this subject review area is acceptable.

17.4.3.9.2 Risk-Significance Methodology

The staff reviewed the detailed methodology used to evaluate, identify, and prioritize the list of risk-significant SSCs, which is given in Section 2.0, "Risk Significance Methodology," of NEDO-33411. As discussed in Item E of the Commission policy contained in the SRM for SECY-95-132 and the 1996 version of SRP Section 17.4, the application should describe an acceptable methodology for evaluating, identifying, and prioritizing SSCs according to their degree of risk significance, using a combination of probabilistic, deterministic, or other methods of analysis. The staff expects the methodology to include the use of information obtained from the following sources:

- Risk evaluations that cover the full spectrum of potential events and the range of plant operating modes considered in ESBWR DCD Tier 2, Chapter 19.0, which includes the use of non-PRA evaluations (e.g., SMA) when PRAs have not been performed
- Industry operating experience and relevant component failure databases
- Expert panels

The roles and responsibilities of expert panels should be described, since they play an important part in reviewing the information associated with risk-significance determinations and could compensate for the limitations of the PRA.

The staff's findings from the review of this subject area are described below. Based on its review, the staff identified areas where it needed additional information to complete its review.

RAI 17.4-19 discussed that Section 2.1, "Risk Significant Thresholds," of NEDO-33411, Revision 0, provided the common-cause failure (CCF) threshold criteria (i.e., common-cause basic events having an RAW greater than or equal to 50 are considered potentially risk-significant). The RAW for a common-cause event generally reflects the relative increase in core damage frequency (CDF) or large release frequency (LRF) that would exist if a set of components or an entire system were made unavailable. The staff requested that GEH provide the basis for the common-cause threshold criteria.

In response to RAI 17.4-19, GEH provided the basis for the risk-significance threshold criteria of CCFs. The basis includes the following:

- The guidance presented in the 2005 report Nuclear Energy Institute (NEI) 00-04, Revision 0, "10 CFR 50.69 SSC Categorization Guideline," uses a RAW significance threshold for CCF events (i.e., RAW greater than or equal to 20) that is a factor of 10 greater than the threshold for single-failure events (i.e., RAW greater than or equal to 2). For consistency, the CCF threshold for the ESBWR (i.e., RAW greater than or equal to 50) is also a factor of 10 greater than the ESBWR single-failure threshold (i.e., RAW greater than or equal to 5). RG 1.201, "Guidelines for Categorizing Structures, Systems, and Components in Nuclear Power Plants According to Their Safety Significance," Revision 1, issued May 2006, endorses NEI 00-04, with appropriate clarifications and exceptions.
- The current guidance in NEI 00-04 suggests that risk-significant CCF events have a RAW value of greater than or equal to 20. This value is used for current operating plants, which have CDF values of approximately 1×10^{-6} /year (yr) and higher. For a CDF of 1×10^{-5} /yr, a RAW of 20 corresponds to a CDF of 2×10^{-4} /yr, if the CCF event is true. This corresponds to a CDF increase of 1.9×10^{-4} /yr. A risk-significant increase in CDF is typically accepted as 1.0×10^{-6} /yr for operating plants. A RAW value of 50 for the ESBWR correlates to a CDF increase of approximately 6×10^{-7} /yr, much less than the increase for an operating plant with a RAW value of 20.

The staff finds that the GEH response to RAI 17.4-19 is adequate. In determining the risk significance of SSCs, the common industry practice for operating reactors is to apply recommended thresholds (i.e., FV greater than or equal to 0.005 at the component level and RAW greater than or equal to 2.0) for plants with CDF values in the range of 1×10^{-4} /yr to 1×10^{-6} /yr. However, this practice may not necessarily apply to new reactors that have significantly lower CDF and LRF values (e.g., 1×10^{-8} /yr for the ESBWR). Also, as stated in Appendix A to Revision 1 of RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," the thresholds for defining risk significance should be a function of the baseline CDF and LRF, rather than being fixed for all plants. The following risk-significance thresholds, described in Section 17.1.2 of NEDO-33201, "ESBWR Certification Probabilistic Risk Assessment," Revision 6, are applied for the ESBWR and were reviewed by the staff under Chapter 19 of the ESBWR DCD:

- FV greater than or equal to 0.01

- RAW greater than or equal to 5.0 for individual events
- RAW greater than or equal to 50 for CCFs

In addition, FV values for basic events representing the various failure modes of the same component are summed and then compared to the threshold. Basic events that do not meet the threshold values are considered potentially not risk-significant (NRS), and the expert panel reviews the results to complete the risk-significance determination. The threshold values used for individual events (i.e., FV greater than or equal to 0.01 and RAW greater than or equal to 5.0) are consistent with those values used in the certified "ABWR Standard Safety Analysis Report," Chapter 19, Appendix 19K, issued August 1996. The use of a threshold criterion for CCF events is an appropriate strategy in prioritizing SSCs according to risk significance, based on NEI 00-04, which provides guidelines for categorizing SSCs according to their risk significance for current operating plants in support of 10 CFR 50.69 and which RG 1.201 endorses, with appropriate clarifications and exceptions. Based on the preceding discussion, the staff finds that the GEH use of risk-significance threshold criteria is adequate. Therefore, RAI 17.4-19 is resolved.

RAI 17.4-25 discussed that Section 2.1.2 of NEDO-33411, Revision 0, stated the following:

For example, a system that has an undeveloped basic event above the risk thresholds is evaluated in a sensitivity study by quantifying the effect of deleting that system entirely. If the revised CDF is less than $1.0 \times 10^{-6}/\text{yr}$ and if the revised results do not introduce any new systems above the risk thresholds, then the system is considered NRS. Undeveloped events representing functions that are safety-related or RTNSS are retained and evaluated with respect to other basic events representing those functions.

An undeveloped event represents a higher level event that is not broken down into lower basic events, because further resolution of that event is not necessary for proper evaluation, or the information necessary for developing this event is not currently available. For example, an undeveloped event may represent multiple failure modes of a single component, a single train of components, multiple components in parallel, and so on.

The staff's understanding of the criterion described in GEH's statement quoted above is that undeveloped events not representing functions that are safety-related or RTNSS are subject to the $1.0 \times 10^{-6}/\text{yr}$ criteria, and undeveloped events representing functions that are safety-related or RTNSS are evaluated with respect to other basic events representing those functions. Though the $1.0 \times 10^{-6}/\text{yr}$ criteria may be appropriate for some undeveloped events (e.g., an undeveloped event representing failure of several systems), it is not appropriate in the general sense. The staff requested that GEH justify or revise the $1.0 \times 10^{-6}/\text{yr}$ criterion used for evaluating risk significance of undeveloped events to a more appropriate criterion.

In response to RAI 17.4-25, GEH stated that it would update the methodology in Section 2.1.2 of NEDO-33411 to specify that undeveloped events are evaluated on a case-by-case basis. Initially, the undeveloped events will be treated as single component failures and will be subject to the most limiting FV and RAW significance thresholds described in Section 2.1 of NEDO-33411; this process ensures that all potentially risk-significant undeveloped events are identified. Once identified, the undeveloped events can be either included as risk-significant or dismissed as NRS, with appropriate justification. For example, one reason for dismissing an

undeveloped event could be a RAW less than 50 for a system that requires multiple component failures to fail its function.

The staff finds that the GEH response to RAI 17.4-25 sufficiently addresses the concerns associated with this RAI. The process for evaluating undeveloped events for risk significance is appropriate and would capture all potentially risk-significant undeveloped events. The staff confirmed that NEDO-33411 was revised accordingly. Based on the above discussion, RAI 17.4-25 is resolved.

RAIs 17.4-20, 30, and 31 addressed the GEH use of SMA to identify risk-significant SSCs. From NEDO-33411, Revision 0, it was not clear whether the scope of the D-RAP included SSCs that were determined to be NRS based on PRA results, but risk-significant based on SMA results. The staff requested that GEH clarify this issue.

In response to RAIs 17.4-20, 17.4-30, and 17.4-31, GEH stated that SSCs that are identified as NRS based on PRA results, but are risk-significant based on SMA, are not in the scope of the D-RAP because their assumed PRA reliabilities are not what causes them to be risk-significant.

The staff found that the GEH response to RAIs 17.4-20, 17.4-30, and 17.4-31 did not address the concerns associated with these RAIs. The risk-significant SSCs identified by SMA are credited as part of the safe-shutdown paths evaluated under SMA. In addition to being capable of withstanding seismic events, these SSCs need to have high reliability and availability to perform their safe-shutdown functions. Therefore, these SSCs should be in the scope of the D-RAP. The SMA is another tool used to identify risk-significant SSCs for the D-RAP, in accordance with the Commission policy contained in the SRM for SECY-95-132. In RAIs 17.4-20 S01, 17.4-30 S01, and 17.4-31 S01, the staff requested that GEH include in the D-RAP the SSCs identified as risk-significant under SMA or provide a more appropriate basis for not including these SSCs. In response, GEH stated that SSCs identified as risk-significant under SMA will be included in the scope of the D-RAP.

The staff finds that the GEH response to RAIs 17.4-20 S01, 17.4-30 S01, and 17.4-31 S01 sufficiently addresses the concerns associated with these RAIs. The staff confirmed that GEH clarified NEDO-33411 to state that the scope of the D-RAP includes the risk-significant SSCs identified by SMA. Based on the above discussion, RAIs 17.4-20, 17.4-30, and 17.4-31 are resolved.

The detailed methodology that GEH used to evaluate, identify, and prioritize the list of risk-significant SSCs includes the use of the following:

- Quantitative results from the PRA models described in Chapter 19 of DCD Tier 2
- Focused PRA analyses to identify RTNSS SSCs (i.e., RTNSS Criteria C and D)
- Insights from the SMA
- Risk insights and assumptions from the PRA and severe accident evaluations
- Industry operating experience to identify SSCs not modeled explicitly in the PRA that could contribute significantly to either initiating a core damage event or causing an adverse operator interaction at an ESBWR

- Expert panel to review the information associated with risk-significance determinations

Based on the discussion in this section, the staff concludes that the detailed methodology that GEH used to evaluate, identify, and prioritize the list of risk-significant SSCs described in Section 2.0 of NEDO-33411 is adequate and meets the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, this subject review area is acceptable.

17.4.3.9.3 Risk-Significant SSCs in the Scope of the D-RAP

The NRC reviewed the list of risk-significant SSCs, which GEH developed under NEDO-33411, Sections 2.0 and 3.0, "Expert Panel Review." As discussed in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4, the application should contain a complete list of risk-significant SSCs based on an acceptable methodology that uses a combination of probabilistic, deterministic, or other methods of analysis.

The following provides the staff's findings from the review of this subject area. The SSCs in the scope of the ESBWR D-RAP include: (1) all RTNSS SSCs identified under ESBWR DCD Tier 2, Section 19A, and (2) all risk-significant SSCs identified under NEDO-33411. The staff confirmed that GEH identified the risk-significant SSCs in accordance with the risk-significance methodology presented in Section 2.0 of NEDO-33411. Based on its review, the staff identified areas where it needed additional information to complete its review of the list of risk-significant SSCs.

In the following RAIs, the staff identified additional SSCs that are considered potentially risk-significant, based on specific PRA results and risk insights, and should be evaluated for inclusion in Table 6 of NEDO-33411. The following RAIs identify these additional SSCs:

- 17.4-30 and 17.4-30 S01 (SSCs associated with the standby liquid control system)
- 17.4-31 and 17.4-31 S01 (SSCs associated with the ICS)
- 17.4-32, 33, 34 (SSCs associated with the uninterruptible alternating current [ac] power supply system)
- 17.4-38, 39 (SSCs associated with the gravity-driven cooling system)
- 17.4-44 and 17.4-44 S01 (main control room and remote shutdown panel)
- 17.4-45 (SSCs associated with the ICS)
- 17.4-52 (SSCs associated with low-voltage distribution and uninterruptible ac power supply)

In response to these RAIs, GEH re-evaluated the risk significance of these additional SSCs, considering the requantified PRA results associated with Revision 5 of NEDO-33201. The staff confirmed these evaluations and verified the risk significance of the additional SSCs identified in the RAIs listed above. The staff confirmed that GEH had included the additional SSCs determined to be risk-significant in Table 6 of NEDO-33411, Revision 2. Based on the above discussion, the RAIs listed above are resolved.

The staff requested that GEH provide the bases for considering some SSCs as NRS. The following RAIs identify these SSCs:

- 17.4-26 (SSCs associated with the balance of plant chilled water system)
- 17.4-26 (SSCs associated with the condensate and feedwater system)
- 17.4-29 (SSCs associated with the instrument air system)
- 17.4-46 and 17.4-46 S01 (SSCs associated with the standby liquid control system electrical heaters)
- 17.4-54 (SSCs associated with the control rod drive system and condensate and feedwater system)

In response to these RAIs, GEH provided the bases for considering these SSCs as NRS. The staff finds that the GEH response sufficiently addressed the concerns associated with these RAIs. Also, the staff confirmed that these SSCs are NRS under the requantified PRA results associated with Revision 5 of NEDO-33201. Based on the above discussion, the RAIs listed above are resolved.

The staff requested in RAI 17.4-36 and RAI 17.4-36 S01 that GEH more clearly identify the risk-significant SSCs in Table 6 of NEDO-33411 through the use of text descriptions and specific SSC identification numbers, when applicable. Clearly identifying the risk-significant SSCs is important to ensure that the list of risk-significant SSCs is effectively communicated to the organizations that implement the D-RAP (e.g., the COL applicants, design engineers, QA staff) in accordance with the essential elements (i.e., organization, design control, procedures and instructions, records, corrective action, and audit plans) discussed in DCD Tier 2, Section 17.4.5. In response to RAI 17.4-36 S01, GEH more clearly described the risk-significant SSCs using text descriptions, which the staff finds to be acceptable (note, the risk-significant SSCs are not identified through specific component identification numbers because component identification numbers have not been assigned to these SSCs within the DCD). The staff confirmed that the clarified text descriptions were incorporated into Revision 2 of NEDO-33411; therefore, RAI 17.4-36 is resolved.

Based on the discussion in this section, the staff confirmed that GEH identified the risk-significant SSCs in accordance with the risk-significance methodology presented in Section 2.0 of NEDO-33411. The staff concludes that the evaluation and identification of risk-significant SSCs described in Sections 2.0 and 3.0 of NEDO-33411 are adequate and meet the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, this subject review area is acceptable.

In conclusion, based on the discussion in this section, the staff finds that LTR NEDO-33411 adequately identifies the risk-significant SSCs in the scope of the D-RAP and describes the evaluation methodology used to determine these risk-significant SSCs. LTR NEDO-33411 meets the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and SRP Section 17.4. Therefore, LTR NEDO-33411 is acceptable.

17.4.4 Conclusion

The NRC reviewed Section 17.4 of ESBWR DCD Tier 2, Revision 9, including the referenced LTR NEDO-33289 and LTR NEDO-33411, Revision 2. The staff finds that GEH has addressed the required information relating to the RAP. In addition, the staff concludes that the ESBWR RAP is acceptable and meets the guidance in Item E of the Commission policy contained in the SRM for SECY-95-132 and in SRP Section 17.4.

18.0 HUMAN FACTORS ENGINEERING

18.1 Introduction

18.1.1 General Description of the Review

This chapter of the safety evaluation report (SER) provides the U.S. Nuclear Regulatory Commission (NRC) staff's review of the human factors engineering (HFE) of the GE-Hitachi Nuclear Energy (GEH) economic simplified boiling-water reactor (ESBWR). The staff completed this review as part of the larger design certification review being conducted by the NRC under Title 10 of the *Code of Federal Regulations* (10 CFR) Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants." The staff conducted this review in accordance with Chapter 18 of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants (LWR Edition)," March 2007 (hereafter referred to as the SRP). Consistent with SRP Chapter 18, the review used the detailed review criteria in NUREG-0711, Revision 2, "Human Factors Engineering Program Review Model."

Design control document (DCD) Tier 2, Revision 9, Chapter 18 incorporates by reference 12 Licensing Topical Reports (LTRs) corresponding to the 12 areas of review discussed in Section 18.1.3 of this report. Five of these LTRs have both proprietary and nonproprietary versions. The remaining seven LTRs are nonproprietary. The applicant uses "NEDE-" to designate the proprietary versions of the LTRs and "NEDO-" to designate the nonproprietary versions. Where the staff relies on nonproprietary information to make its findings, the staff cites the "NEDO-" version of an LTR in Chapter 18 of this report. Where the staff relies on proprietary information to make its findings and is able to discuss it in a nonproprietary manner, the staff cites the "NEDE-" version of an LTR in Chapter 18 of this report. However, the staff determined that it had to rely on and use proprietary information in only three of the LTRs to address the NUREG-0711, Revision 2 review criteria for the corresponding areas of review. These three LTRs address task analysis, Human-System Interface (HSI) design, and human factors verification and validation. These areas of review are discussed in Sections 18.5, 18.8, and 18.11 of this report, respectively. Accordingly, the staff has prepared a proprietary safety evaluation report (SER) for chapter 18 which addresses the NUREG-0711, Revision 2 review criteria using both proprietary and nonproprietary information. This report discusses the information submitted by the applicant in a nonproprietary manner and references the Chapter 18 proprietary SER where necessary to address the NUREG-0711, Revision 2 review criteria. The Agencywide Documents Access and Management System (ADAMS) Accession Number for the proprietary SER is ML101940387.

18.1.2 Purpose of Review

The overall purpose of the HFE review is to verify the following:

- The applicant has integrated HFE into plant development, design, and evaluation.
- The applicant has provided HFE products (e.g., HSIs, procedures, and training) that allow safe, efficient, and reliable performance of operation, maintenance, test, inspection, and surveillance tasks.
- The HFE program and its products reflect state-of-the-art human factors principles and satisfy all specific regulatory requirements.

18.1.3 Areas of Review

SRP Chapter 18 identifies 12 areas of review for successful integration of human characteristics and capabilities into nuclear power plant design. These areas of review correspond to the 12 elements of an HFE program identified in NUREG-0711 and are listed below.

- HFE program management
- Operating experience review (OER)
- Functional requirements analysis (FRA) and function allocation (FA)
- Task analysis
- Staffing and qualifications
- Human reliability analysis (HRA)
- HSI design
- Procedure development
- Training program development
- Human factors verification and validation (V&V)
- Design implementation
- Human performance monitoring

For these areas, the staff conducted and documented the ESBWR review using the review criteria from NUREG-0711. In addition, for a limited number of specific topics, the staff used criteria from other review guidance documents as identified in the appropriate sections. Sections 18.2 through 18.13 of this report detail the results of the review.

18.1.4 Regulatory Criteria Applicable to All Areas of Review

This section describes those regulatory criteria applicable to all 12 areas of review.

As required by 10 CFR 52.47, applications for design certification of new reactor designs must meet the technically relevant portions of the Three Mile island (TMI) requirements contained in 10 CFR 50.34(f) (except for 10 CFR 50.34(f)(1)(xii), 10 CFR 50.34(f)(2)(ix), and 10 CFR 50.34(f)(3)(v)). The staff bases its HFE review on current regulatory requirements established after TMI and contained in 10 CFR 50.34(f). The staff reviews HFE aspects of new main control rooms (MCRs) to verify that they reflect state-of-the-art human factors principles as required by 10 CFR 50.34(f)(2)(iii), and that personnel performance is appropriately supported. 10 CFR 50.34 requires a safety parameter display system (SPDS), automatic indication of bypassed and operable status of safety systems, and monitoring capability in the MCR for a variety of system parameters.

For plants licensed under 10 CFR Part 52, the requirements of 10 CFR 50.34(f) are incorporated via 10 CFR 52.47 and 10 CFR 52.79. Meeting these requirements provides evidence that plant design, staffing, and operating practices are acceptable and that there is reasonable assurance that plant safety will not be compromised by human error or by deficiencies in HSIs, considering both hardware and software.

Sections 18.2 through 18.13 of this report each include a regulatory criteria section that is based on review objectives taken from the corresponding NUREG-0711 section. The objectives provide a high-level summary of the detailed review criteria used in the review.

18.1.5 Levels of Review

The staff in general may perform three different levels of review, depending on the type of information provided: complete element level, implementation plan (IP) level, and programmatic level. For the ESBWR, the applicant provided information for IP or complete element level reviews, so the programmatic level review was not used.

A complete element level of review is performed when the applicant has completed the HFE activity and submitted a description of it for staff review. The review is completed when the applicant has acceptably met all of the NUREG-0711 criteria.

An IP level of review is performed when the applicant has not completed an HFE activity. Page 2 of NUREG-0711 states the following:

An IP gives the applicant's proposed methodology for meeting the acceptance criteria of the element. An IP review gives the applicant the opportunity to obtain staff review of and concurrence in the applicant's approach before conducting the activities associated with the element. Such a review is desirable from the staff's perspective because it provides the opportunity to resolve methodological issues and provide input early in the analysis or design process when staff concerns can more easily be addressed than when the effort is completed.

Table 18-1 summarizes the level of review performed by the staff for each of the 12 HFE areas of review related to the ESBWR design certification.

Table 18-1 Level of HFE Review.

HFE Area	Level of Review
HFE Program Management	Complete Element
Operating Experience Review	Implementation Plan
Functional Requirements Analysis and Function Allocation	Implementation Plan
Task Analysis	Implementation Plan
Staffing and Qualifications	Implementation Plan
Human Reliability Analysis	Implementation Plan
Human-System Interface Design	Implementation Plan
Procedure Development	See Chapter 13.5
Training Program Development	See Chapter 13.2
Human Factors Verification and Validation	Implementation Plan
Design Implementation	Implementation Plan
Human Performance Monitoring	Implementation Plan

18.1.6 Use of Design Acceptance Criteria for Human Factors Engineering

The NRC accepts the use of design acceptance criteria (DAC), as described in SECY-92-053, "Use of Design Acceptance Criteria during 10 CFR Part 52 Design Certification Reviews," February 19, 2002. DAC are considered a special kind of inspection, test, analysis, and acceptance criteria (ITAAC), and they are used in lieu of detailed design information in the HFE area. The NRC allows the use of the DAC process because providing detailed design information is not practicable for applicants using technologies that change so rapidly that the design may have become obsolete between the time the NRC certifies the design and the time a plant is eventually built. For this section and the remaining sections of this report, the use of the acronym ITAAC refers to all ITAAC including DAC.

The applicant has identified ITAAC for each HFE element that has an IP with the exception of the procedure and training elements which do not have ITAAC because they are operational programs. These ITAAC are contained in DCD Tier 1, Section 3.3. The staff's evaluation of these ITAAC is in Section 14.3.9 of this report. The acceptance criteria of the ITAAC are linked closely to the IPs. Because the key technical information for the HFE element is contained in the IP and the acceptance criteria of the ITAAC are linked to the IP, each IP is designated as Tier 2* with the exception of the IP for the procedure and training elements. This designation prohibits changes to the plan without prior NRC approval. The expiration date of the Tier 2* designation must be after completion of the IP and related ITAAC and is selected as first achievement of full power following the finding required by 10 CFR 52.103(g). In Request for Additional Information (RAI) 18.2-19, the staff requested that all IPs be designated as Tier 2*. RAI 18.2-19 was being tracked as an open item in the SER with open items. In its response, the applicant stated that all IPs would be designated as Tier 2*. Based on the applicant's response, RAI 18.2-19 is resolved. The staff confirmed that the applicant satisfactorily implemented this change in Revision 5 of the DCD. The applicant subsequently requested that the IPs for the procedure and training elements not be designated as Tier 2*. The staff finds that the IPs for the procedure and training elements do not need to be Tier 2* because they are for operation programs addressed by DCD Tier 2, Chapter 13.

The staff will verify the final design was developed in accordance with the design process described in the ITAAC. This may occur via a design certification amendment, the combined license (COL) application review, or the ITAAC closure process. The staff identified two RAIs closely related to the implementation of the DAC approach described above. In RAI 14.3-211, the staff requested that the applicant revise the 11 design descriptions in DCD Tier 1, Table 3.3-1 to refer to the applicable IPs rather than the overall "MMIS and HFE Implementation Plan." RAI 14.3-211 was being tracked as an open item in the SER with open items. In its response, the applicant agreed to implement this change. Based on the applicant's response, RAI 14.3-211 is resolved. In RAI 14.3-271, the staff requested that the applicant revise DCD Tier 1, Table 3.3-1 for each design commitment to ensure that they accurately reflect the methodology described in the IPs. RAI 14.3-271 was being tracked as an open item in the SER with open items. In its response, the applicant revised the ITAAC in DCD Tier 1, Table 3.3-1 to include key output items from the IPs. Based on the applicant's response, RAI 14.3-271 is resolved. The staff confirmed that the applicant satisfactorily implemented changes from RAIs 14.3-211 and 14.3-271 in DCD Tier 2, Revision 5.

18.1.7 Minimum Inventory

Section 18.14 of this report evaluates the applicant's minimum inventory. MCR designs incorporate, and are therefore influenced by, rapidly changing technologies. Accordingly, the

NRC allows detailed MCR design to be deferred and evaluated after design certification under “DAC ITAAC” (see SECY- 92-053). The concept of Minimum Inventory originated as part of the Commission’s general resolution of the limited MCR design detail that would be available at the time of design certification. The concept of Minimum Inventory was intended to ensure that design certification applicants provided, as a minimum, sufficient MCR design information for the staff to make a safety determination at the time of design certification. However, as the HFE design process and the staff’s evaluation of the process has matured, there has been increased recognition that the HFE design process, as outlined in NUREG–0711, can and should be the primary process used to identify all controls, displays, and alarms (CDAs) needed in the MCR design. The staff evaluated the Minimum Inventory using the direction provided in the SRP Section 14.3.9, recognizing that the NUREG–0711 process, as implemented by the applicant, will validate and continue to develop the design characteristics associated with the parameters that make up the minimum inventory. For clarity, “Minimum Inventory” is capitalized when referring to the inventory of CDAs specifically covered by SECY-92-053 and SRP Section 14.3.9.

18.1.8 Generic Issues Related to Human Factors Engineering

Section 18.15 of this report evaluates the generic issues related to HFE. A brief summary of each generic issue is provided followed by a description of how the technical issue is evaluated in an applicable section of this report. If open items are identified in the applicable sections, the generic issue is characterized as open for the ESBWR design.

18.2 Human Factors Engineering Program Management

18.2.1 Regulatory Criteria

The objective of reviewing HFE program management is to verify that the applicant has an HFE design team with the responsibility, authority, placement within the organization, and composition to verify that the design commitment to HFE is met. The team should also be guided by a plan to provide reasonable assurance that the HFE program is properly developed, executed, overseen, and documented. This plan should describe the technical program elements that verify that all aspects of the HSI, procedures, and training are developed, designed, and evaluated on the basis of accepted HFE principles.

To review the applicant’s HFE program management, the staff used the review criteria in NUREG–0711, Section 2.4.

18.2.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.2, describes the ESBWR HFE program management. DCD Tier 2, Revision 9, Section 18.2 incorporates by reference NEDE-33217P (proprietary), Revision 6, “ESBWR Man-Machine Interface System and Human Factors Engineering Implementation Plan (or the MMIS-HFE Plan).” The nonproprietary version of NEDE-33217P is designated as NEDO-33217.

The staff also reviewed the following ESBWR documents:

- GEH responses to RAIs 18.2-1 through 18.2-20
- ESBWR DCD Tier 2, Revision 9, Chapter 19

- GEH ESBWR Baseline Record Review (BRR), Draft 1A, January 2007
- GEH Quality Assurance Plan, NEDO-33181, Revision 1, “NP-2010 COL Demonstration Project Quality Assurance Plan”
- GE Hitachi Nuclear Energy Quality Assurance Program Description, NEDO-11209-04A, Revision 8

In addition to reviewing the applicant’s design documents, the staff conducted regulatory audits in January 16-18, and July 25-27, 2007, (combined audit summary report: ML101960241) to examine how the applicant initially applied the processes described in these documents to the ESBWR design and to evaluate the documentation of the results. Following design certification, the staff will need to verify the final results of the design analyses for the other HFE elements, as part of the staff’s COL application review or through the ITAAC process, to ensure that the design was completed in accordance with the process specified in the design certification, as reflected in the ITAAC.

18.2.3 Staff Evaluation

The staff performed a complete element level of review as described in NUREG–0711 and Section 18.1 of this report.

This section presents the applicable review criteria from NUREG–0711 (reproduced below) followed by an evaluation of each criterion. HFE program management review topics include the following:

- General HFE program goals and scope (six review criteria)
- HFE team and organization (four review criteria)
- HFE process and procedures (six review criteria)
- HFE issues tracking (four review criteria)
- Technical program (three review criteria)

The applicant has identified the Man-Machine Interface System (MMIS)-HFE Plan and each of the HFE element IPs as Tier 2* in DCD, Revision 9, Chapter 18.

18.2.3.1 NUREG–0711 Review Criteria

18.2.3.1.1 General Human Factors Engineering Program Goals and Scope

NUREG–0711 includes six criteria for this topic. The sixth criterion addresses plant modifications and is not applicable to new reactors, thus the staff evaluated the first five criteria as discussed below.

- (1) HFE Program Goals—The general objectives of the program should be stated in “human-centered” terms, which, as the HFE program develops, should be defined and used as a basis for HFE test and evaluation activities. Generic “human-centered” HFE design goals include the following:
 - Personnel tasks can be accomplished within time and performance criteria

- The HSIs, procedures, staffing and qualifications, training, and management and organizational support will support a high degree of operating crew situation awareness
- The plant design and allocation of functions will maintain operation vigilance and provide acceptable workload levels (i.e., to minimize periods of operator underload and overload)
- The operator interfaces will minimize operator error and will provide for error detection and recovery capability

Evaluation of Criterion (1)

NEDE-33217P, Revision 6, Section 3.1.2, states that the goal of the MMIS implementation process is to ensure that the vital role personnel play in the plant operation is supported through human-centered design, development, and operational activities. Section 3.2.2 further states the goals for the ESBWR HFE process in human-centered terms which include personnel task accomplishment, support for situation awareness, acceptable workload, minimization of error, and support for recovery when errors occur. These are the four general directives in NUREG-0711. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for program goals acceptable.

- (2) **Assumptions and Constraints**—An assumption or constraint is an aspect of the design, such as a specific staffing plan or the use of specific HSI technology that is an input to the HFE program rather than the result of HFE analyses and evaluations. The design assumptions and constraints should be clearly identified.

Evaluation of Criterion (2)

NEDE-33217P, Revision 6, Section 1.2, Item 1, clearly identifies the assumptions and constraints of the ESBWR HFE design by listing them. These include predecessor advanced boiling-water reactor (ABWR) designs, standard design features, safety requirements, and staffing plans. The IP references appropriate DCD sections that further address these aspects of the design. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for assumptions and constraints acceptable.

- (3) **Applicable Facilities**—The HFE program should address the main control room, remote shutdown facility, technical support center (TSC), emergency operations facility (EOF), and local control stations (LCSs).

Evaluation of Criterion (3)

NEDE-33217P, Revision 6, Section 1.2, Item 2, and DCD Tier 2, Revision 9, Section 18.2, specify the facilities to which the MMIS-HFE Plan applies. These include the facilities in NUREG-0711, namely: the MCR, remote shutdown control station, TSC, and the EOF. Also included are LCSs that have a safety function or have been identified by the ESBWR task analysis.

Accordingly, the staff finds the MMIS-HFE Plan treatment of the criterion for applicable facilities acceptable.

- (4) Applicable HSIs, Procedures and Training—The applicable HSIs, procedures, and training included in the HFE program should include all operations, accident management, maintenance, test, inspection and surveillance interfaces (including procedures).

Evaluation of Criterion (4)

NEDE-33217P, Revision 6, Section 1.2, Item 3, notes the applicable HSIs, procedures, and training included in the program. These encompass operations, accident management, maintenance, test, inspection, and surveillance interfaces (including procedures) for those systems that have safety significance, which are the activities specified for inclusion in NUREG-0711. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for applicable HSIs, procedures, and training acceptable.

- (5) Applicable Plant Personnel—Plant personnel who should be addressed by the HFE program include licensed control room operators, as defined in 10 CFR Part 55 and the following categories of personnel defined by 10 CFR 50.120: non-licensed operators, shift supervisor, shift technical advisor, instrument and control technician, electrical maintenance personnel, mechanical maintenance personnel, radiological protection technician, chemistry technician, and engineering support personnel. In addition, any other plant personnel who perform tasks that are directly related to plant safety should be addressed.

Evaluation of Criterion (5)

NEDE-33217P, Revision 6, Section 1.2, Item 5, identifies applicable personnel, including the categories of personnel identified in the review criterion in NUREG-0711. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for applicable personnel acceptable.

18.2.3.1.2 Human Factors Engineering Team and Organization

- (1) Responsibility—The team should be responsible (with respect to the scope of the HFE program) for (a) the development of all HFE plans and procedures; (b) the oversight and review of all HFE design, development, test, and evaluation activities; (c) the initiation, recommendation, and provision of solutions through designated channels for problems identified in the implementation of the HFE activities; (d) verification of implementation of team recommendations; (e) assurance that all HFE activities comply with the HFE plans and procedures; and (f) scheduling of activities and milestones.

Evaluation of Criterion (1)

NEDE-33217P, Revision 6, Section 3.1.4.1, describes the HFE design team's responsibilities. This section states that the HFE design team's specific duties are to guide and oversee the design implementation activity and to ensure that the execution and documentation of each step in the activity is carried out in accordance with the established program and procedures. In addition, this section addresses each of the responsibilities identified in the review criterion in NUREG-0711. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for the HFE team's responsibility acceptable.

- (2) Organizational Placement and Authority—The primary HFE organization(s) or function(s) within the organization of the total program should be identified, described, and illustrated (e.g., charts to show organizational and functional relationships, reporting relationships,

and lines of communication). When more than one organization is responsible for HFE, the lead organizational unit responsible for the HFE program plan should be identified. The team should have the authority and organizational placement to provide reasonable assurance that all areas of responsibility are accomplished and to identify problems in the implementation of the overall plant design. The team should have the authority to control further processing, delivery, installation, or use of HFE products until the disposition of a nonconformance, deficiency, or unsatisfactory condition has been achieved.

Evaluation of Criterion (2)

NEDE-33217P, Revision 6, Section 3.1.4.1, describes the project organization and the responsibilities of key functions in the organization. Figure 3.1.4-1, "Engineering, Quality, and Project Management Organization," provides an organization chart and lines of communication. The HFE team is situated within the software project engineering function. The team is fully responsible for the development of HFE IPs and for the use of these plans in designing the HFE aspects of the ESBWR. NEDE-33217P describes the overall guidance for HFE activities, with additional details provided in the individual HFE element IPs. The HFE team designs, controls, and manages the HFE activities and oversees the V&V of the design and implementation of the HFE aspects of the plan. Consistent with the responsibilities of the HFE team defined in NEDE-33217P, the team has the authority to ensure that all responsibilities are accomplished, to determine where their inputs are necessary, and to control overall use of its work products. This authority includes control over any nonconformance or deficiency within its areas of responsibility to ensure an acceptable solution. Furthermore, the team ensures that HFE work performed by outside organizations conforms to the applicant HFE plans, procedures, and guidelines. The organizational structure, responsibilities, and authorities defined in the plan provide reasonable assurance that the HFE activities will be successfully accomplished. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for the HFE team's organizational placement and authority responsibility acceptable.

- (3) Composition—The HFE design team should include the expertise described in the Appendix to NUREG-0711.

Evaluation of Criterion (3)

NEDE-33217P, Revision 6, Section 3.1.4.1, describes the team's expertise and skills, which include the areas of expertise identified in NUREG-0711. In response to RAIs 18.2-5 and 18.2-6, the applicant provided an Attachment A, which outlined a skills matrix for HFE activities, and an Attachment B, which provided a qualification cross-matrix for ESBWR HFE participants. These matrices list each member of the HFE team and their pertinent skills. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for the HFE team's composition acceptable.

- (4) Team Staffing—Team staffing should be described in terms of job descriptions and assignments of team personnel.

Evaluation of Criterion (4)

NEDE-33217P, Revision 6, Table 3.1.4-1 provides the assignment of necessary skills to the various HFE element activities. Further, in response to RAIs 18.2-5 and 18.2-6, the applicant provided Attachment A, which outlined a skills matrix for HFE activities, and Attachment B, which provided a qualification cross-matrix for ESBWR HFE participants. These matrices list

each member of the HFE team and their pertinent skills. The combination of the two lists provides the job descriptions and assignments information for the entire team.

In addition, the staff evaluated the team composition in the January and July 2007 regulatory audits. The applicant provided detailed job descriptions and assignment information for the individual team members and their qualifications. The staff noted that additional personnel beyond those on the above attachments had been added to the team. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for the HFE team staffing acceptable.

18.2.3.1.3 Human Factors Engineering Process and Procedures

(1) General Process Procedures—The process through which the team will execute their responsibilities should be identified. The process should include procedures for:

- Assigning HFE activities to individual team members
- Governing the internal management of the team
- Making management decisions regarding HFE
- Making HFE design decisions
- Governing equipment design changes
- Design team review of HFE products

Evaluation of Criterion (1)

NEDE-33217P, Revision 6, Section 3.1.4.2, addresses general process procedures. The plan references the applicant's project quality assurance (QA) plan (NEDO-33181). This plan also refers to the GE nuclear QA program description, (NEDO-11209-04A). The staff reviewed these QA plans and found that they provided general overall QA for the HFE program aspects of the project. NEDO-33181 provides the overall scope of the QA program and describes how it relates to and incorporates aspects of other QA requirements and guidance. This guidance includes: Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," and the International Organization for Standardization's standard ISO-9001, issued in 2000. NEDO-33181 endorses NEDO-11209-04A and related detailed implementing procedures for use with the ESBWR design project. The NRC previously reviewed the NEDO-11209-04A QA program as part of the ABWR design certification and found it to be acceptable. As discussed under the previous two acceptance criteria, the applicant provided satisfactory information related to the assignment of HFE activities to team members and the overall structure and management of the team. Section 3 of NEDO-11209-04A addresses design control and design review.

The staff further evaluated general process procedures during the January and July 2007 regulatory audits at which the applicant explained the use of its procedures. The applicant provided lists of personnel on the human factors team and organization charts showing personnel. The applicant introduced team personnel to the NRC audit team and various responsible personnel on the team gave presentations on the progress in their respective areas. The staff was able to interact with GEH personnel and obtained answers related to their processes and results to date. The staff finds that the procedures used to govern the HFE program are sufficient and are being satisfactorily implemented at the time of the audit. The staff acknowledges that QA plans and procedures may be updated periodically, but that they are always subject to NRC inspection and audit.

In view of the above, the staff finds the MMIS-HFE Plan's treatment of the criterion for general HFE process procedures acceptable.

- (2) Process Management Tools—Tools and techniques (e.g., review forms) to be utilized by the team to verify they fulfill their responsibilities should be identified.

Evaluation of Criterion (2)

In RAI 18.2-10, the staff requested that the applicant clarify the general process management tools included in the design certification to address this criterion. RAI 18.2-10 was being tracked as an open item in the SER with open items. The first two responses provided plans and schedules for addressing the RAI. The last response provided a satisfactory description of the process management tools and provided revisions to NEDE-33217P. These changes are described below.

Appendix E to NEDE-33217P, Revision 6, addresses process management tools. The applicant's process management for HFE is based on higher level engineering operating procedures which govern activities such as work planning and scheduling, design reviews, independent design verification, design record files, and document initiation and change. Appendix E describes the process as applied to the HFE program. It describes the development, execution, control, output reviews, and closure of all of the HFE activities within the scope of the HFE program and technically governed by the separate IPs for each. Appendix E also identifies specific management responsibilities for the management of the HFE program. For example, for each HFE task, a work plan is developed by a qualified process lead in accordance with higher level GEH engineering procedures. A functional lead reviews the work plan with respect to, among other things, ESBWR planning and scheduling needs. The responsible manager then approves the plan.

Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for process management tools acceptable. Based on the direction the applicant included in the plan, RAI 18.2-10 is resolved.

- (3) Integration of HFE and Other Plant Design Activities—The integration of design activities should be identified, that is, the inputs from other plant design activities to the HFE program and the outputs from the HFE program to other plant design activities. The iterative nature of the HFE design process should be addressed.

Evaluation of Criterion (3)

NEDE-33217P, Revision 6, Section 3.2.4.2, addresses the integration of HFE and other plant design activities. Figure 3.1.4-2, "Process Feedback and Issues Disposition," and Figure 3.2.4-1 of the plan depict the process that executes the integration of the engineering disciplines. It is iterative in structure and the process continues until handed over to the Licensee. Each of the IPs for the various NUREG-0711 elements describes the process further and provides more detail regarding the specific element. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for HFE integration acceptable.

- (4) HFE Program Milestones—HFE milestones should be identified so that evaluations of the effectiveness of the HFE effort can be made at critical check points and the relationship to the integrated plant sequence of events is shown. A relative program schedule of HFE

tasks showing relationships between HFE elements and activities, products, and reviews should be available for review.

Evaluation of Criterion (4)

NEDE-33217P, Revision 6, Section 3.1.4.2, describes HFE program milestones, thus enabling the effectiveness of the HFE effort to be evaluated at critical checkpoints. The milestones are to be identified in terms of their relationship to HFE program activities. This is acceptable at the ESBWR design certification stage.

However, the staff expects a COL applicant to address the status of the milestones in a manner that will facilitate timely review by the staff at each milestone. In RAI 14.3-210, the staff requested that the applicant include a COL information item concerning the schedule for ITAAC closure. RAI 14.3-210 was being tracked as an open item in the SER with open items. In response, the applicant provided Attachment 14.3A to Chapter 14 of the ITAAC. The attachment summarizes material found in 10 CFR 52.99(a) and Regulatory Guide (RG) 1.206, "Combined License Applications for Nuclear Power Plants (LWR Edition)," related to the closure of ITAAC. In response to RAI 14.3-210 S01, COL Information Item 14.3A-1-1 was included in DCD Tier 2, Appendix 14.3A to ensure that COL applicants provide an ITAAC closure schedule and identify the closure process to be used. Based on the applicant's response, RAI 14.3-210 is resolved. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for HFE program milestones acceptable.

- (5) HFE Documentation—HFE documentation items should be identified and briefly described along with the procedures for retention and access.

Evaluation of Criterion (5)

NEDE-33217P, Revision 6, Section 3.1.4.2, addresses HFE and software documentation. This section states that the applicant's project QA plan includes retention and limited access provisions, and controls the HFE documentation and document management. The applicant's project QA plan, NEDO-33181, provides general overall QA for the HFE program aspects of the project.

In addition, NEDE-33217P, Revision 6 identifies the documentation associated with individual HFE activities discussed in subsequent sections of this report. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for HFE documentation acceptable.

- (6) Subcontractor HFE Efforts—HFE requirements should be included in each subcontract and the subcontractor's compliance with HFE requirements should be periodically verified.

Evaluation of Criterion (6)

NEDE-33217P, Revision 6, Section 3.1.4.2, addresses subcontractor HFE efforts. It specifies that each subcontract include requirements for HFE and that these requirements be verified in accordance with the applicant's project QA plan. The applicant's project QA plan, NEDO-33181, provides general overall QA for the HFE program aspects of the project. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for subcontractor HFE requirements acceptable.

18.2.3.1.4 Human Factors Engineering Issues Tracking

- (1) Availability—A tracking system should be available to address human factors issues that are (a) known to the industry (defined in the Operating Experience Review element, see Section 18.3 of this report) and (b) identified throughout the life cycle of the HFE aspects of design, development, and evaluation. Issues are those items that need to be addressed at some later date and thus need to be tracked to provide reasonable assurance that they are not overlooked. It is not necessary to establish a new system to track HFE issues that is independent from the rest of the design effort. An existing tracking system may be adapted to serve this purpose (such as a plant's corrective action program [CAP]).

Evaluation of Criterion (1)

NEDE-33217P, Revision 6, Section 3.1.4.3 describes the HFE Issue Tracking System (HFEITS). This system ensures that HFE problems, issues and human engineering discrepancies (HEDs) identified throughout the development and evaluations of MMIS implementation are addressed. The tracking system includes the known industry issues and operating experience of the ESBWR predecessor plants that were identified in their OER and were determined to be appropriate for inclusion in the ESBWR design (see Section 18.3 of this report for the staff's review of operating experience). The plan specifies that the CR design team develops the project work instructions that address issue tracking. Appendix A to the MMIS-HFE Plan provides additional detail about the structure and functioning of the HFEITS. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for HFEITS availability acceptable.

- (2) Method—The method should document and track HFE issues from identification until the potential for negative effects on human performance has been reduced to an acceptable level.

Evaluation of Criterion (2)

NEDE-33217P, Revision 6, Section 3.1.4.3 and Appendix A, demonstrate that the proposed HFEITS documents and tracks HFE issues to a satisfactory resolution. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for HFEITS methodology acceptable.

- (3) Documentation—Each issue or concern that meets or exceeds the threshold established by the design team should be entered into the system when first identified, and each action taken to eliminate or reduce the issue or concern should be thoroughly documented. The final resolution of the issue should be documented in detail, along with information regarding design team acceptance.

Evaluation of Criterion (3)

NEDE-33217P, Revision 6, Section 3.1.4.3 and Appendix A, demonstrate that the proposed HFEITS appropriately documents and tracks issues. As discussed in Appendix A, the proposed HFEITS has 23 fields for inputting information, including fields to document each of the information items identified in the criterion (e.g., the issue description [field 6] and disposition [field 15]) set forth in NUREG-0711. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for HFEITS documentation acceptable.

- (4) Responsibility—When an issue is identified, the tracking procedures should describe individual responsibilities for issue logging, tracking and resolution, and resolution acceptance.

Evaluation of Criterion (4)

NEDE-33217P, Revision 6, Section 3.1.4.3 and Appendix A, demonstrate that responsibilities are appropriately specified. The proposed HFEITS has 23 fields for inputting information, including fields to clearly identify issue priority, assignment of actions to responsible organizations and individual action owners, due dates, actual completion dates, and resolution verification. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for assignment of responsibility acceptable.

18.2.3.1.5 Technical Program

NUREG-0711 includes five criteria for this topic. The fourth and fifth criteria address plant modifications and are not applicable to new reactors, thus only the first three criteria are evaluated below.

- (1) The general development of IPs, analyses, and evaluation of the following should be identified and described:
- OER
 - FRA and FA
 - Task analysis
 - Staffing and qualifications
 - HRA
 - HSI design
 - Procedure design
 - Training design
 - Human factors V&V
 - Design implementation
 - Human performance monitoring

Evaluation of Criterion (1)

In RAI 18.2-18, the staff asked the applicant to clarify the description of the technical program in NEDE-33217P. NEDE-33217P, Revision 3, included summary descriptions of the IPs which could potentially conflict with the language in the IPs. RAI 18.2-18 was being tracked as an open item in the SER with open items. The applicant's responses provided a general plan for deleting duplicative material in the NEDE-33217P, but no markups. The applicant's responses also provided a schedule to address the RAI. NEDE-33217P, Revision 4, deleted the duplicative material as identified in the RAI responses. NEDE-33217P, Revision 4, retained necessary and sufficient material to address the technical program review criterion as described below (as implemented in NEDE-33217P, Revision 6). Based on the applicant's responses and NEDE-33217P revisions, RAI 18.2-18 is resolved.

NEDE-33217P, Revision 6, Section 2.1.2, references the individual HFE activity IPs for each HFE element noted in the criterion above. Sections 3.1.4, 3.2.4, and 3.2.6 describe the development and use of the various IPs. Table 3.1.4-1 links the project team expertise to the

various HFE element IPs. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for HFE IPs acceptable.

- (2) The HFE requirements imposed on the design process should be identified and described. The standards and specifications that are sources of HFE requirements should be listed.

Evaluation of Criterion (2)

Section 2 of NEDE-33217P, Revision 6, describes the HFE requirements used in the design process. A fairly extensive listing of nuclear industry documents is included that encompasses codes and standards, NRC documents, relevant GEH reports, and other industry documents, such as those from the Institute of Electrical and Electronics Engineers (IEEE) and the Electric Power Research Institute. The list includes all appropriate documents. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for HFE requirements acceptable.

- (3) HFE facilities, equipment, tools, and techniques (such as laboratories, simulators, rapid prototyping software) to be utilized in the HFE program should be specified.

Evaluation of Criterion (3)

NEDE-33217P, Revision 6, Section 3.2.1, describes HFE facilities, tools, equipment, and techniques used in the HFE program. The overall report presents the general approach and discusses the use of dynamic models, CR mockups, part-test simulators, and full-scope simulators. Moreover, in the January and July 2007 regulatory audits, the staff obtained additional information on the applicant's use of simulator-based engineering and the various tools and their applications, which provided additional details on the application of HFE techniques and tools in the ESBWR design. Accordingly, the staff finds the MMIS-HFE Plan's treatment of the criterion for identification of facilities and tools acceptable.

18.2.3.2 Relationship to Other Documents

18.2.3.2.1 DCD Tier 1, Section 3.3, "Human Factors Engineering"

DCD Tier 1, Revision 9, Section 3.3, provides a high-level discussion of the Human Factors Program Plan. Since HFE program management is reviewed at a completed element level, there are no ITAAC associated with this area. Section 14.3.9 of this report addresses the staff's review of the HFE ITAAC described in DCD Tier 1, Revision 9, section 3.3.

18.2.3.2.2 DCD Tier 2, Section 18.2, "MMIS and HFE Program Management"

In RAI 18.2-20, the staff requested that the applicant update the reference to the ESBWR MMIS and HFE IP in the DCD. RAI 18.2-20 was being tracked as an open item in the SER with open items. The applicant indicated that it would update the references to all HFE IPs in the DCD. The staff confirmed that the applicant included appropriate references in DCD Tier2, Revision 6. Based on the applicant's response, RAI 18.2-20 is resolved.

DCD Tier 2, Revision 9, Section 18.2 provides a high-level description of the MMIS and HFE program for the ESBWR, which includes an overview of the IP, the scope of the program, a description of the HFE design team, and a discussion of the HFE issue tracking system. NEDE-33217P, Revision 6, and NEDO-33217, Revision 6, which are reviewed throughout Chapter 18 of this report, provide more detail, are referenced by this DCD chapter, and are designated as

Tier 2*. Thus, Tier 2, together with the referenced IP, provides an acceptable description of the ESBWR HFE program management. The staff finds the DCD Tier 2, Revision 9, Chapter 18 treatment of HFE program management acceptable.

18.2.4 Conclusions

The staff reviewed the HFE program management at a complete element level (see Section 18.1.4 of this report for a discussion of review levels) using the review criteria in Section 2.4 of NUREG-0711. As discussed above, the staff concludes that the HFE program management for the ESBWR has identified general HFE program goals and scope, specified an acceptable HFE team and organization, implemented appropriate HFE process and procedures, developed an HFE issues tracking system, and established an acceptable HFE technical program. Accordingly, the staff concludes that the applicant's HFE program management is acceptable at the complete element level.

18.3 Operating Experience Review

18.3.1 Regulatory Criteria

The objective of reviewing the applicant's OER is to verify that it has identified and analyzed HFE-related problems and issues in previous designs that are similar to the current design under review. In this way, negative features associated with predecessor designs may be avoided in the current one while retaining positive features.

To review the applicant's OER, the staff used the review criteria in NUREG-0711, Section 3.4.

18.3.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.3, describes the ESBWR OER. DCD Tier 2, Revision 9, Section 18.3, incorporates by reference NEDE-33217P, Revision 6, and NEDO-33262, Revision 3, "ESBWR Human Factors Engineering Operating Experience Review Implementation Plan."

The staff also reviewed the following ESBWR documents:

- ESBWR DCD Tier 1, Revision 9, Section 3.3
- ESBWR DCD Tier 2, Revision 9, Chapter 19
- NEDO-33201, Revision 6
- GEH Response to RAIs 18.3-1 through 18.3-21
- GEH ABWR First-of-a-Kind Engineering (FOAKE) Program, "Operating Experience/Lessons Learned Evaluation," Revision 0, February 2, 1996, (audited material)
- GEH, "Standby Liquid Control Functional Requirements Analysis Report (Lungmen)," October 16, 1997, (audited material)
- GEH, "Reactor Water Clean-up Functional Requirements Analysis Report (Lungmen)," October 16, 1997, (audited material)

- General Electric ESBWR Baseline Record Review (BRR), Draft 1A, January 2007, (audited material)

In addition to reviewing the applicant's design documents, the staff conducted a regulatory audit on July 14, 2007, to examine the initial application of the processes described in these documents to the ESBWR design and to evaluate the documentation of the results. The staff also notes that DCD Tier 1, Revision 9, Table 3.3-2, contains an ITAAC verification of the OER element.

18.3.3 Staff Evaluation

The staff performed an IP level of review as described in NUREG-0711 and Section 18.1 of this report.

This section presents the applicable review criteria from NUREG-0711 (reproduced below), followed by an evaluation of each criterion. OER review topics include the following:

- Scope (five review criteria)
- Issue analysis, tracking, and review (three review criteria)

In addition, this section addresses related documents (i.e., DCD Tier 1 and Tier 2 information).

18.3.3.1 NUREG-0711 Review Criteria

18.3.3.1.1 Scope

NUREG-0711 includes five scope-related criteria, as described below.

- (1) Predecessor/Related Plants and Systems—The review should include information pertaining to the human factors issues related to the predecessor plant(s) or highly similar plants and plant systems. Some useful information may be found in the plant's CAP. Also, when personnel are unfamiliar with the proposed technology, attention should be paid to the operating experience of other plants that already have the technology.

Evaluation of Criterion (1)

NEDO-33262, Revision 3, discusses the review of human factors issues associated with predecessor plants in several ways. First, the applicant notes that a review of the industry experience with the operation of selected MMIS equipment technologies includes reviewing those designs similar to the proposed design. This process includes a review of the literature pertaining to the human factors issues related to similar system applications of such technologies and interviews with personnel experienced with the operation of these systems. The OER also classifies and evaluates events reported by boiling-water reactor (BWR) and ABWR predecessor systems upon which the design is based.

In RAI 18.3-1, the staff asked how experience with isolation condensers would be addressed if the OER focused on ABWR work instead of previous BWRs. Current BWR fleet experience with isolation condenser systems would not have been applicable to the ABWR, since it does not have isolation condensers, but current BWR fleet experience would be pertinent to the ESBWR. In response, the applicant stated that the ESBWR OER includes operational experience gained from previous BWRs with isolation condensers. The ESBWR OER includes

experience from the ABWR and the current BWR fleet. The staff finds that the applicant's response is acceptable because the ESBWR OER includes BWRs with isolation condensers and the ABWR. Based on the applicant's response, RAI 18.3-1 is resolved.

NEDO-33262, Revision 3, Section 1.2, "Scope," notes that an OER was performed as part of the first-of-a-kind engineering (FOAKE) effort for the ABWR. The ABWR system functional requirements analysis (SFRA) reports for each system document the results. The staff reviewed two example SFRA reports for the Lungmen ABWR. These reports used the system functions from the system design descriptions. The reports were reasonably comprehensive and focused on operator actions. They included information from the OER performed for the system that was the subject of the report. NEDO-33262, Section 1.2, also discusses the baseline record review (BRR), which identifies significant differences between the ESBWR design and predecessor designs and establishes a process for evaluation and resolution of identified differences. The staff reviewed a draft of the BRR (issued January 2007) at the GEH facility that discussed, among other items, the sources and types of predecessor information and the transition to the ESBWR from earlier BWR designs. The applicant's approach appeared reasonable and thorough.

NEDO-33262, Revision 3, Section 3, states that the OER process includes both plant operations and HFE design topics. For the ESBWR, three predecessor ABWR plants have been operating for several years and three additional ABWRs are in the design and construction stages. There is also the entire U.S. and worldwide BWR fleet that preceded the ABWRs and from which the ABWR and ESBWR designs were developed.

NEDO-33262, Revision 3, Section 3.1.3, states that the HFE design team interviewed plant operations personnel and previous HFE team members and personnel from the ABWR predecessor plant and previous BWR plants, as well as operators who are involved with the full-scale simulator training. At a meeting at its facility in January 2007, the applicant discussed a trip to Japan made specifically to gather OER-type information from the operating Japanese ABWRs. NEDO-33262, Revision 3, specifies that the information and analysis results are included in the BRR/OER database, used for the ESBWR design as appropriate, and summarized in the OER results summary report.

The OER Plan considers predecessor and highly similar plant HFE issues. Accordingly, the staff finds the OER Plan's treatment of the criterion for predecessor/related plants and systems acceptable.

(2) Recognized Industry HFE Issues—NUREG/CR-6400, ["HFE Insights for Advanced Reactors Based upon Operating Experience,"] issues should be addressed. The issues are organized into the following categories:

- Unresolved safety issues/generic safety issues
- TMI issues
- NRC generic letters (GLs) and information notices (INs)
- Reports of the former NRC Office for Analysis and Evaluation of Operational Data
- Low power and shutdown operations
- Operating plant event reports

Evaluation of Criterion (2)

NEDO-33262, Revision 3, Section 1.2, specifies that the OER addresses recognized industry HFE issues that are documented in NRC reports, such as NUREG-0933, "A Prioritization of Generic Safety Issues," and NUREG/CR-6400. NEDO-33262, Revision 3, Section 1.2, also states that the OER analyzes experience summary documents in detail to integrate the insights that support enhancement of human actions (HAs) which affect the risk and reliability of both normal and outage operations (e.g., generic safety issues defined by the NRC). NEDO-33262, Revision 3, Section 3, "Methods," lists further areas and sources to be reviewed.

NEDO-33262, Revision 3, Appendix A, "Example Identification of Human Interactions from Event Experience Related to BWRs," provides a detailed example of an OER of current BWR plants related to shutdown operations. The applicant provided this as an example for conducting an OER for the ESBWR, specifically to illustrate how the ESBWR OER team reviews this experience as possible input to the ESBWR design.

In Section 3.2.3.5 of NEDO-33262, Revision 3, the applicant also noted that the ESBWR design is an extension of the ABWR design, which is an extension of earlier BWR designs. Previous OERs were reviewed and actions were taken to minimize or eliminate identified human interaction deficiencies at BWR/ABWR plants. This philosophy continues with the ESBWR design. NEDO-33262, Revision 3, specifies that the ESBWR HFE design team review the lessons learned and recommendations from the shutdown study, along with other OER results, and enter applicable items into HFEITS for resolution. This process provides input into the ESBWR design, operator training, and procedure improvements.

The OER Plan addresses the categories of recognized industry HFE issues identified in the criterion as described in detail above. Accordingly, the staff finds the OER Plan's treatment of the criterion for recognized industry HFE issues acceptable.

- (3) Related HFE Technology—The OER should address related HFE technology. For example, if touch screen interfaces or computerized procedures are planned, HFE issues associated with their use should be reviewed.

Evaluation of Criterion (3)

NEDO-33262, Revision 3, Section 1.2, states that review of experience and identification of problems in prior MMIS implementations, including human factors problems, is addressed throughout the design process. The Scope section also notes that the review of the MMIS technologies includes both a review of literature pertaining to the human factors issues related to similar system applications of such technologies and interviews with personnel experienced with the operation of these systems. NEDO-33262, Sections 3 and 3.2, provide a list of the HFE design topics and technologies to be addressed. Section 3 states that HFE design topics include selection of alarm and annunciation elements; displays, control, and automation elements; information processing and job aids; real-time communications with plant personnel and other organizations; and procedures, training, staffing and qualifications, and job design. NEDO-33262, Revision 3, Section 5.1, specifies that the results summary report includes the review of HSI equipment and technologies.

The OER Plan considers related HFE technology as described in detail above. Accordingly, the staff finds the OER Plan's treatment of the criterion for related HFE technology acceptable.

- (4) Issues Identified by Plant Personnel—Personnel interviews should be conducted to determine operating experience related to predecessor plants or systems. The following topics should be included in the interviews as a minimum:
- Plant Operations
 - Normal plant evolutions (e.g., startup, full power, and shutdown)
 - Instrument failures (e.g., safety-related system logic and control unit, fault tolerant controller [nuclear steam supply system], local “field unit” for multiplexer [MUX] system, MUX controller [balance of plant], break in MUX line)
 - HSI equipment and processing failure (e.g., loss of video display units, loss of data processing, loss of large overview display)
 - Transients (e.g., turbine trip, loss of offsite power, station blackout, loss of all feedwater, loss of service water, loss of power to selected buses or MCR power supplies, and safety/relief valve transients)
 - Accidents (e.g., main steamline break, positive reactivity addition, control rod insertion at power, control rod ejection, anticipated transients without scram [ATWS], and various-sized loss-of-coolant accidents [LOCAs])
 - Reactor shutdown and cooldown using remote shutdown system
 - HFE Design Topics
 - Alarm and annunciation
 - Display
 - Control and automation
 - Information processing and job aids
 - Real-time communications with plant personnel and other organizations
 - Procedures, training, staffing/qualifications, and job design

Evaluation of Criterion (4)

NEDO-33262, Revision 3, Section 1.2, provides for obtaining and incorporating feedback from utility operators on the needs of operators, maintainers, testers, and outage planners. Section 3 states that the OER includes conducting personnel interviews to determine the operating experience related to predecessor plants or systems. At a minimum, interview topics include plant operations and HFE design topics. NEDO-33262, Sections 3 and 3.2, contain an acceptable list of HFE design topics to be addressed by personnel interviews. Section 3.1 addresses the area of plant operations and notes potential topics for the conduct of interviews with experienced operators. Section 3.1.4 contains an acceptable list of operational areas. The intent of this portion of the ESBWR OER is to receive candid input from plant staff that may not be provided in published reports. Design teams from predecessor designs also serve as potential contributors to OERs. The information gathered is intended to be based upon facts, such as the results of evaluations or test results, rather than personal opinion. The applicant has completed some interviews and is planning to conduct further interviews of plant operations personnel and previous HFE team members or personnel from the ABWR Lungmen predecessor plant and previous BWR plants. The HFE design team interviews operators that are involved with the full-scale simulator training for additional OER input. Additionally, during the January 2007 meeting at its Wilmington, NC, facility, the applicant described a trip to Japan that included interviews with operations personnel from operating ABWRs to obtain OER-type information.

The OER Plan includes the conduct of personnel interviews on plant and HFE design topics to determine operating experience related to predecessor plants or systems, as described in detail above. Accordingly, the staff finds the OER Plan's treatment of the criterion for issues identified by plant personnel acceptable.

- (5) Risk-Important Human Actions (HAs)—The OER should identify risk-important HAs that have been identified as different from predecessor plants or where errors have occurred in the execution of risk important HAs. These HAs should be identified as requiring special attention during the design process to lessen their probability of failure.

Evaluation of Criterion (5)

NEDO-33262, Revision 3, Section 1.2, specifies that the ESBWR system designers use the BRR database, in conjunction with an OER database, to analyze risk-important HAs. The scope of the OER plan includes analyzing experience summary documents and integrating insights to support enhancement of HAs affecting the risk and reliability of both normal and outage operations. NEDO-33262, Section 3.2.3.1 includes the use of shutdown probabilistic risk assessment (PRA) studies as part of the OER. Section 3.2.3.4 discusses a classification scheme that includes consideration of the critical tasks identified in the ESBWR Human Factors Engineering Human Reliability Analysis Plan and the Task Analysis Plan. The purpose of the classification is to place issues into categories that can facilitate their disposition.

NEDO-33262, Section 3.2.4, "Applications," discusses how the OER addresses risk-important HAs in predecessor and similar plant designs and how experience related to these actions is used to improve human performance and lower risk in the ESBWR.

NEDO-33262, Section 5.1, notes that the results summary report will describe the risk important HAs from predecessor plants and their resolution and risk important HAs from the OER that warrant special attention in the design process.

The OER Plan considers risk-important HAs that have been identified as different from predecessor plants, as well as cases in which errors have occurred in the execution of risk important HAs described in detail above. Accordingly, the staff finds the OER Plan's treatment of the criterion for risk-important HAs acceptable.

18.3.3.1.2 Issue Analysis, Tracking, and Review

NUREG-0711 includes three criteria for this topic as described below.

- (1) Analysis Content—The issues should be analyzed with regard to the identification of:
 - Human performance issues, problems, and sources of human error
 - Design elements that support and enhance human performance

Evaluation of Criterion (1)

NEDO-33262, Revision 3, Section 3.2.3.4, "Classification," states that individual OER information files are screened and classified for the human factors aspects of operating experience, according to a scheme or framework. The purpose of the classification is to place issues into categories to facilitate their disposition. Section 1.2 of the OER Plan discusses the framework.

NEDO-33262, Revision 3, Section 3.2.3.5, "Identification of Human Issues," states that event data or analyzed reports are selected and considered for ESBWR design HFE support. These data and reports can be analyzed to identify problematic operations and tasks and to point to potential human factor enhancements for all aspects of human performance. This includes the HSI design, procedures, personnel training, and CR staffing and qualifications.

The OER Plan identifies issues and design elements related to human performance as described in detail above. Accordingly, the staff finds the OER Plan's treatment of the criterion for analysis content acceptable.

- (2) Documentation—The analysis of operating experience should be documented in an evaluation report.

Evaluation of Criterion (2)

NEDO-33262, Revision 3, Section 5.1, describes the proposed summary report. The report addresses the scope of NEDO-33262, Section 1.2, by summarizing the results of the OERs, including OERs of previous nuclear power plant HSI designs that identify human performance issues and the HFE solutions that support human performance improvements. The applicant provided a proposed outline for the report which addresses the specified areas of NUREG-0711.

The OER Plan describes an evaluation report called a results summary report that documents the analysis of operating experience as described in detail above. Accordingly, the staff finds the OER Plan's treatment of the criterion for documentation acceptable.

- (3) Incorporation into the Tracking System—Each operating experience issue determined to be appropriate for incorporation in the design (but not already addressed in the design) should be documented in the issue tracking system.

Evaluation of Criterion (3)

NEDE-33217P, Revision 6, describes the overall methodology for the functioning of the HFEITS. In particular, Sections 3.1.4.2 and 3.1.4.3, Figure 3.1.4-2, and Appendix A all discuss the purpose and workings of the HFEITS. The methods and types of items to be entered into the system are described. In addition, NEDO-33262, Revision 3, describes the OER Plan and various operating experience issues that are input to the HFEITS.

The OER Plan includes an issue tracking system called HFEITS that documents appropriate operating experience issues for incorporation in the design as described in detail above. Accordingly, the staff finds the OER Plan's treatment of the criterion for incorporation into the HFEITS acceptable.

18.3.3.2 Relationship to Other Documents

18.3.3.2.1 DCD Tier 1, Section 3.3, "Human Factors Engineering"

DCD Tier 1, Revision 9, Table 3.3-2, contains the Tier 1 ITAAC developed by the applicant for HFE. Table 3.3-2 contains 10 items, one for each element of NUREG-0711 (except HFE program management, procedures and training) plus one item that addresses integrated system validation scenarios. Each item in Table 3.3-2 is linked to the corresponding ESBWR element

IP. As described in Section 14.3.9 of this report, DCD Tier 1, Revision 9, Section 3.3, provides ITAAC sufficient to confirm that applicable HFE elements are completed in accordance with their respective IPs, which includes confirming that the OER is completed in accordance with the IP (NEDO-33262, Revision 3), which the staff has reviewed and approved.

18.3.3.2.2 DCD Tier 2, Section 18.3, “Operating Experience Review”

DCD Tier 2, Revision 9, Section 18.3 provides the primary description of OER activities, which summarizes the OER program, including the purpose, objectives and scope, and the OER methodology. This section of the DCD also references the detailed IP (NEDO-33262, Revision 3), which is designated as Tier 2*. As discussed above, NEDO-33262, Revision 3, describes an OER program which conforms to the NUREG–0711 criteria for OER. Thus, DCD Tier 2, Revision 9, Chapter 18, together with the referenced IP, provides an acceptable description of the ESBWR OER program.

18.3.4 Conclusions

The staff has reviewed the ESBWR OER at an IP level (see Section 18.1.4 of this report for a discussion of review levels) using the review criteria in Section 3.4 of NUREG–0711. The staff concludes that the ESBWR OER IP, as described in NEDO-33262, Revision 3, provides an acceptable methodology to identify and analyze HFE-related problems and issues in previous designs that are similar to the ESBWR design. This methodology provides a means to ensure that negative features associated with predecessor designs may be avoided in the ESBWR while retaining positive features. DCD Tier 1, Revision 9, Section 3.3, provides ITAAC sufficient to confirm that the OER is completed in accordance with the IP (NEDO-33262, Revision 3), which the staff has reviewed and approved. Accordingly, the staff concludes that the applicant’s OER is acceptable at the IP level.

18.4 Functional Requirements Analysis and Function Allocation

18.4.1 Regulatory Criteria

The objective of reviewing FRA and FA is to verify that the applicant has (1) defined the plant's functions that must be performed to satisfy plant safety objectives and (2) allocated those functions to human and system resources in a manner that takes advantage of human strengths and avoids human limitations.

To review the applicant’s FRA and FA plans, the staff used the review criteria in NUREG–0711, Section 4.4.

18.4.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.4, describes the ESBWR FRA and FA. DCD Tier 2, Revision 9, Section 18.4, incorporates by reference NEDE-33217P, Revision 6; NEDO-33219, Revision 4, “ESBWR System Functional Requirements Analysis Implementation Plan”; NEDO-33220, Revision 4, “ESBWR Allocation of Functions Implementation Plan”; and NEDE-33220P, Revision 4, a proprietary version of the Allocation of Functions IP.

The staff also reviewed the following ESBWR documents:

- ESBWR DCD Tier 1, Revision 9, Section 3.3

- ESBWR DCD Tier 2, Revision 9, Chapter 19
- NEDO-33201, Revision 6
- GEH responses to RAIs 18.4-1 through 18.4-26
- GEH, “Standby Liquid Control Functional Requirements Analysis Report (Lungmen),” October 16, 1997 (audited material)
- GEH, “Reactor Water Clean-up Functional Requirements Analysis Report (Lungmen),” October 16, 1997 (audited material)

The applicant initially submitted NEDO-33219, Revision 0, “ESBWR System Functional Requirements Analysis Implementation Plan,” and NEDO-33220, Revision 0, “ESBWR Allocation of Functions Implementation Plan,” in January 2006. The staff developed and issued RAIs on these documents. Revision 1 to these IPs reflected a significant revision, which led to several followup RAIs. The applicant issued Revision 2 in May 2008 to address the followup RAIs and changes in the methods. Revision 3, issued in April 2009, made only minor changes. The applicant issued Revision 4 in February 2010 to implement a minor modification to the references.

In addition to reviewing the GEH design documents, the staff conducted a regulatory audit in January and July, 2007, to examine the initial application of the processes described in these documents to the ESBWR design and to evaluate the documentation of the results. Following design certification, the staff will verify the final results of the design analyses, either in the COL application or through the ITAAC process, to ensure that the design was completed in accordance with the process specified in the design certification, as reflected in the DAC.

18.4.3 Staff Evaluation

The staff performed an IP level of review, as described in NUREG–0711 and Section 18.1 of this report. This section presents the applicable review criteria from NUREG–0711 (reproduced below) followed by an evaluation of each criterion. This section also addresses related documents (i.e., DCD Tier 1 and Tier 2 information).

18.4.3.1 NUREG–0711 Review Criteria

NUREG–0711 includes 11 criteria for this topic. However, the 11th criterion relates to plant modifications and is not applicable to new plant designs.

- (1) Functional requirements analysis and function allocation should be performed using a structured, documented methodology reflecting HFE principles. An example functional allocation process and considerations are shown in Figure 4.1 of NUREG–0711. The functional requirements analysis and function allocation may be graded based on:
 - The degree to which the functions of the new design differ from those of the predecessor
 - The extent to which difficulties related to plant functions were identified in the plant’s operating experience and will be addressed in the new design.

Evaluation of Criterion (1)

In RAIs 18.4-16 and 18.4-21, the staff identified that (1) the FA decision making guidelines were incomplete, (2) the allocation criteria were too general to be consistently applied, (3) several criteria needed additional clarification, and (4) the appendix providing the criteria used for deciding the FA was inconsistently referenced. As documented through several supplemental RAIs, the staff determined that the necessary level of detail was in the applicant's internal work instructions and needed to be incorporated into the IP NEDE-33220P. RAIs 18.4-16 and 18.4-21 were being tracked as open items in the SER with open items. In response to these RAIs, the applicant provided the information at a level of detail sufficient for the staff to complete its review of the FRA and FA criteria. The applicant incorporated this information into the appropriate IPs. The staff's evaluation of the IPs, as updated through the RAI responses, is described below. Based on the applicant's responses and NEDE-33220P revisions, RAIs-18.4-16 and 18.4-21 are resolved.

NEDO-33219, Revision 4, describes the applicants approach to FRA, and NEDO-33220, Revision 4, describes the applicants approach to FA.

NEDO-33219, Revision 4, describes an overall operational analysis approach that includes FRA, allocation of function, and task analysis. This operational analysis is iterative, as shown in NEDO-33219, Revision 4, Figures 1 through 6. In accordance with NEDO-33219, Revision 4, Section 1, the FRA establishes methods to do the following:

- Denote ESBWR mission and goals
- Conduct the FRA consistent with accepted HFE methods
- Identify critical safety functions
- Validate system functions identified in the ESBWR system design specifications (SDS)
- Define the relationships between high-level functions and plant systems
- Reconcile any differences between plant-level analyses and the SDS

NEDO-33219, Revision 4, Section 1.2, specifies that plant-level and system-level goals and functions are systematically analyzed concurrently. In accordance with Section 3.2.4 of the plan, systems are analyzed with information taken from the SDS. The system-level FRA is linked to the plant-level FRA, which allows the eventual linking of the high level plant mission and functions to system components. The staff reviewed examples of this process during the January 2007 regulatory audit at GEH, and the following was noted. As described in NEDO-33219, Revision 4, Section 3.1, and Figures 2 and 4, the functional relationships between plant functions and system functions are reconciled through a gap analysis that ensures that both plant-level and system-level goals are met. The plant-level FRA is conducted in three phases as the design proceeds: a high-level plant FRA, a design FRA, and a detailed FRA. Section 3.2 and Figure 3 describe the system-level FRA. These FRAs analyze each system and its functions to determine individual task requirements necessary to meet the high-level plant objectives. A gap analysis, described in Section 3.3 and Figure 6, is performed to link the plant and system FRAs and identify any gaps that must be addressed.

NEDO-33220, Revision 4, describes the applicant's structured methodology to allocating to personnel and automation the functions identified by the NEDO-33219, Revision 4, FRA methodology. The methodology is generally based on accepted approaches documented in publications such as NUREG/CR-3331, "A Methodology for Allocation of Nuclear Power Plant Control Functions to Human and Automated Control." As described in Section 3.1.4 of the FA Plan, the scope of the analysis is broad and includes all functions identified in the FA. Section 3

of the FA Plan describes the general methodology, and Section 4 describes the means of implementing the methodology.

NEDO-33220, Revision 4, Section 3.1.2, defines a set of goals for the allocation of function process that emphasizes human performance objectives. These goals include considerations such as minimizing errors and performance of normal, abnormal, and emergency functions.

NEDO-33220, Revision 4, Section 4, and a set of companion figures, especially Figures 3 and 4, present the details of the FA methodology. For safety functions, the methodology guides the analyst through a set of considerations to determine whether the function should be automated or not. Such considerations are at the core of FA methods. Section 4.1.3.1, Item 2, provides the criteria for this analysis, which include the following:

- Regulatory requirement
- Design requirement
- PRA basis assumption
- HRA/PRA risk significance
- OER/BRR significance
- Human cognitive limitations
- Human response time limitations
- Human physical limitations
- Hostile environment, including atmosphere, temperature, and radiation

The applicant provided detailed guidance for FA in Appendix B to NEDE-33220P, Revision 4. Analysts use the guidance to evaluate the factors employed to make allocation decisions. Where it is feasible to do so, quantitative guidance is provided, such as in the assessment of physical workload. The guidance is sufficiently detailed to enable a clear and consistent use of the FA methodology.

The methodology of the FRA Plan also appropriately considers the need for personnel backup of functions for which automation is indicated, as well as automatic backup of functions for which manual performance is indicated.

The allocation process results in functions being automatic, manual, or shared. Shared functions are accomplished by a combination of automation and personnel action. These functions are further analyzed using the considerations in NEDO-33220, Revision 4, Figure 4.

The FRA and FA Plans provide a structured, documented methodology reflecting HFE principles for performing these analyses as described in detail above. Accordingly, the staff finds the treatment of the criterion for a structured methodology in the FRA and FA Plans to be acceptable.

- (2) The functional requirements analysis and function allocation should be kept current over the life cycle of design development and held until decommissioning so that it can be used as a design basis when modifications are considered. Control functions should be re-allocated in an iterative manner, in response to developing design specifics, operating experience, and the outcomes of ongoing analyses and trade studies.

Evaluation of Criterion (2)

NEDO-33219, Revision 4 and NEDO-33220, Revision 4, describe the iterative nature of the operational analyses that include both FRA and FA. Figure 2 depicts these analyses, which are further described in Sections 3.1, 3.2, and 4 of NEDO-33219, Revision 4 and in Figure 1 of NEDO-33220, Revision 4. This methodology inherently ensures that the FRA is kept current over the life cycle of design development.

Additionally, NEDE-33217P, Revision 6, Section 3.1.4.2, "Management Process and Procedures," states the following:

Each licensee is responsible to maintain as-built design bases and SQA [software quality assurance] records during the operating life of the related ESBWR license. A fleet-wide owners' group provides a means of coordination between GEH and the ESBWR licensees to facilitate and maintain uniformity of...Operational Analysis.

The ESBWR operational analysis includes FRA, allocation of function analysis, and task analysis.

The FRA and FA Plans provide for keeping the FRA and FA current and for allocating control functions in an iterative manner, as described in detail above. Accordingly, the staff finds the FRA and FA Plans treatment of the criterion for life-cycle currency acceptable.

- (3) A description of the functions and systems should be provided along with a comparison to the reference plants/systems, i.e., the previous plants or plant systems on which the new system is based. This description should identify differences that exist between the proposed and reference plants/systems. Safety functions (e.g., reactivity control) include functions needed to prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public. For each safety function, the set of plant system configurations or success paths that are responsible for or capable of carrying out the function should be clearly defined. Function decomposition should start at "top-level" functions where a very general picture of major functions is described, and continue to lower levels until a specific critical end-item requirement emerges (e.g., a piece of equipment, software, or human action [HA]). The functional decomposition should address the following levels:
- High-level functions (e.g., maintain reactor coolant system [RCS] integrity) and critical safety functions (e.g., maintain RCS pressure control)
 - Specific plant systems and components

Evaluation of Criterion (3)

NEDO-33219, Revision 4, Sections 3 and 4.1, describe the top-level or plant FRA to be performed. These analyses identify the major functions needed to achieve the plant goals and subgoals, both safety and economic, and high-level functions for safe operation. The analyses then proceed to a lower level to identify processes, critical safety functions (CSFs), subfunctions, indications, controls, and accident monitoring parameters. Section 4.1.3.7 describes the identification of the CSFs, which include reactivity control, reactor pressure vessel overpressure protection, core cooling, and containment heat removal. NEDO-33219, Revision 4, Figure 4, summarizes this process.

NEDO-33219, Revision 4, Section 4.2, describes the system-level FRA. This portion of the overall FRA describes and analyzes each system in the design, the majority of which were inherited from predecessor plants (i.e., the earlier BWR fleet and the ABWRs). The analyses identify the functions performed by each system, down to the division, channel, or train level. The analyses also identify the processes necessary for a system to accomplish its functions, support elements and components for each process, system alignments and configurations, and the details of transitions between configurations. NEDO-33219, Revision 4, Figure 5, depicts the system-level FRA.

NEDO-33219, Revision 4, Section 3.3, describes a gap analysis that is performed to address any discrepancies between the plant-level and system-level FRAs. Any discrepancies are addressed in the design or are added to the HFEITS for later correction. Figure 6 summarizes the system function gap analysis.

Moreover, in addition to reviewing the GEH design documents, the staff conducted a regulatory audit in January, 2007 during which the staff reviewed two examples of typical system FRAs performed by GEH for a new ABWR, specifically, the standby liquid control system and the reactor water cleanup system. The staff notes that the FRAs were generally performed in accordance with the IP and provided appropriate analyses of the system functions. They also included information from the OER performed for the system being evaluated.

The FRA Plan calls for descriptions of functions and systems and the identification of differences between proposed and reference plants. The FRA Plan includes performing a functional decomposition that addresses high-level functions and specific plant systems and components, as described in detail above. Accordingly, the staff finds the FRA Plan's treatment of the criterion for functional description and decomposition acceptable.

(4) A description should be provided for each high-level function which includes:

- Purpose of the high-level function
- Conditions that indicate that the high-level function is needed
- Parameters that indicate that the high-level function is available
- Parameters that indicate the high-level function is operating (e.g., flow indication)
- Parameters that indicate the high-level function is achieving its purpose (e.g., reactor vessel level returning to normal)
- Parameters that indicate that operation of the high-level function can or should be terminated

Note that parameters may be described qualitatively (e.g., high or low). Specific data values or setpoints are not necessary at this stage.

Evaluation of Criterion (4)

In RAI 18.4-26, the staff noted that the applicant had removed information addressing this criterion from NEDO-33219, Revision 1, and moved it to a work instruction. The staff determined that this information was needed in NEDO-33219 and requested that the applicant return the information. RAI 18.4-26 was being tracked as an open item in the SER with open items. In the RAI responses, the applicant indicated that it would move appropriate information addressing this criterion back into NEDO-33219. The staff finds that the applicant identified the

information at a level of detail sufficient for the staff to complete its review of the criterion and had incorporated this information into NEDO-33219. The staff's evaluation of NEDO-33219 for this criterion, as updated through the RAI responses, is described below. Based on the applicant's responses and the NEDO-33219 revision, RAI 18.4-26 is resolved.

DCD Tier 2, Revision 9, Section 18.4.1.1 states that the FRA will provide methods and criteria for conducting both the plant-level FRA and the system-level FRA and will also provide descriptions for each identified function. NEDO 33219, Revision 4, Section 4.3.3.8, "Plant Function Operational Summary," states that the FRA will determine the following for each high-level plant function:

- Purpose of the plant function
- The plant condition or conditions which require the plant function
- Parameter or parameters that represent the availability of the plant system designated to support the plant function
- Parameter or parameters that represent operation of the plant system in support of the plant function
- Parameter or parameters that represent the success of the plant system in support of the function
- Parameter or parameters that indicate when support of the function from the plant system can or should be terminated

Accordingly, the staff finds the FRA Plan's treatment of the criterion for the description of high-level functions acceptable.

- (5) The technical basis for modifications to high-level functions in the new design (compared to the predecessor design) should be documented.

Evaluation of Criterion (5)

The plant-level functional requirements analysis (PFRA) is used to determine the technical basis for each high-level function in the ESBWR. NEDO-33219, Revision 4, Section 3.1 states the following:

The High-level PFRA is performed early in the design process and identifies critical safety functions...The Design PFRA includes plant goals and functions that support the ESBWR mission of generating safe economic electric power during all plant operating modes....

The functions from ESBWR predecessor designs are embedded in the system designs that were inherited from these earlier BWR plants. NEDO-33219, Revision 4, Section 3.2, discusses the SFRA. The SFRA is the second step of the "top-down" approach to FRA and analyzes each system and its functions. The system function gap analysis then determines and resolves any discrepancies between the high-level plant functions and the system functions. NEDO-33219, Revision 4, Section 3.3, describes this process, which is summarized above and which could

result in engineering design changes if needed. The staff finds that this process provides a suitable documented method for modifying functions when needed.

The FRA Plan includes documenting the technical basis for modifications to high-level functions in the new design, as described in detail above. Accordingly, the staff finds the FRA Plan's treatment of the criterion for modifications to high-level functions acceptable.

- (6) The technical basis for all function allocations should be documented; including the allocation criteria, rationale, and analyses method. The technical basis for functional allocation can be any one or combination of the evaluation factors (see Fig 4.1). For example, the performance demands to successfully achieve the function, such as degree of sensitivity needed, precision, time, or frequency of response, may be so stringent that it would be difficult or error prone for personnel to accomplish. This would establish a basis for automation (assuming acceptability of other factors, such as technical feasibility or cost).

Evaluation of Criterion (6)

NEDO-33220, Revision 4, Section 4.1.3, "Process," indicates that the FA process is documented in formal records that capture the criteria, rationale, and analysis method used. NEDO-33220, Revision 4, Section 5, "Results," describes the results summary report that is generated.

As part of the January and July 2007 regulatory audits, the staff examined examples of the applicant approach to documenting FA results. The approach was complete and provided an auditable documentation of the findings. The approach provided a traceable path from high-level requirements analysis through task analysis. The regulatory audit confirmed that NEDO-33220, Revision 4, identifies appropriate documentation approaches. Accordingly, the staff finds the FA Plan's treatment of the criterion for the FA technical basis acceptable.

- (7) The OER should be used to identify modifications to function allocations, if necessary. If problematic OER issues are identified, then an analysis should be performed to (a) justify the original analysis of the function, (b) justify the original human-machine allocation, and (c) identify solutions such as training, personnel selection, and procedure design that will be implemented to address the OER issues.

Evaluation of Criterion (7)

NEDO-33220, Revision 3, Section 4.1.2.1, "Inputs," discusses the process by which OER provides input to all operational analyses, which is illustrated in Figure 1. OER results, which are documented in the OER/BRR, provide input to the ESBWR analysis. OER is listed as one criterion for making allocation decisions in the various subsections of Section 4.1.3.1, "Allocation of Function Flow Chart Process." NEDO-33219, Revision 4, provides that all FRA functions are to be analyzed. OER serves as one basis for making allocation decisions, but is not used to screen out any functions from being analyzed. The availability and use of the OER/BRR as a means to capture operating experience and lessons learned should help ensure the use of that information in the allocation process.

The FA Plan includes performing analyses on problematic OER issues and using the OER to identify modifications to FAs, as described in detail above. Accordingly, the staff finds the FA Plan's treatment of the criterion for use of OER in the FA process acceptable.

- (8) The allocation analysis should consider not only the primary allocations to personnel, but also their responsibilities to monitor automatic functions and to assume manual control in the event of an automatic system failure.

Evaluation of Criterion (8)

The process for allocating functions discussed above with respect to Criterion (1) explicitly incorporates the evaluation of personnel roles in automatic function performance. Similarly, the analysis considers the role of automation in backing up personnel performance. NEDO-33220, Revision 4, Figures 3 and 4, illustrate these considerations, which are described in Section 4.1.3.2, "Shared Function Detailed Flowchart Process." Accordingly, the staff finds the FRA Plan's treatment of the criterion for allocation related to automation acceptable.

- (9) A description of the integrated personnel role across functions and systems should be provided in terms of personnel responsibility and level of automation.

Evaluation of Criterion (9)

The applicant's FRA and FA methodologies incorporate both plant-level and system-level analyses (see NEDO-33220, Revision 4, Figure 2, and NEDO-33219, Revision 4, Figures 3 through 6). Plant-level analyses address the demands of allocations that cut across functions. Those analyses are carried through to the task analysis, where the detailed performance of functions assigned to plant personnel is further analyzed.

The FRA and FA Plans include providing a description of the integrated personnel role across functions and systems in terms of personnel responsibility and level of automation as described in detail above. Accordingly, the staff finds the treatment of the criterion for the integrated role of personnel in the FRA and FA Plans to be acceptable.

- (10) The functional requirements analysis and function allocation should be verified:
- All the high-level functions necessary for the achievement of safe operation are identified.
 - All requirements of each high-level function are identified.
 - The allocations of functions result in a coherent role for plant personnel.

Evaluation of Criterion (10)

NEDO-33219, Revision 4, describes the complete top-down FRA approach used to verify the functional requirements of this criterion. This method does not assume functions from prior designs, but searches for and ensures that all functions and related requirements are identified. The concurrent development of the PFRA and the SFRA provides another check in the method to help ensure completeness. NEDO-33220, Revision 4, Section 3.1.4, explains that the V&V (and other HFE processes) provides feedback that is evaluated to determine whether or not additional iterations of the operational analysis process are warranted in specific areas. These added iterations will be implemented should the V&V process identify any problems with the role of personnel versus automation. This provides reasonable assurance of a coherent role for plant personnel. Accordingly, the staff finds the treatment of the criterion for verification of analyses to be in the FRA and FA Plans acceptable.

18.4.3.2 Relationship to Other Documents

18.4.3.2.1 DCD Tier 1, Section 3.3, “Human Factors Engineering”

DCD Tier 1, Revision 9, Table 3.3-2, contains the Tier 1 ITAAC which the applicant developed for HFE. Table 3.3-2 contains 10 items, one for each element of NUREG–0711 (except HFE program management, procedures and training) plus one item that addresses the integrated system validation scenarios. Each item in Table 3.3-2 is linked to the corresponding ESBWR element IP. As described in Section 14.3.9 of this report, DCD Tier 1, Revision 9, Section 3.3 provides ITAAC sufficient to confirm that applicable HFE elements are completed in accordance with their respective IPs, which includes confirming that the FRA and FA are completed in accordance with their respective IPs (NEDO-33219, Revision 4, and NEDO-33220, Revision 4), which the staff has reviewed and approved.

18.4.3.2.2 DCD Tier 2, Section 18.4, “Functional Requirements Analysis and Allocation of Functions”

In RAI 18.4-25, the staff requested that the applicant address inconsistencies between DCD Tier 2, Revision 3, Section 18.4 and NEDO-33220, Revision 1. RAI 18.4-25 was being tracked as an open item in the SER with open items. In response, the applicant agreed to remove extraneous information from DCD Tier 2. The staff confirmed that the applicant did remove extraneous information from DCD Tier 2, Revision 5, Section 18.4, and that this information was consistent with NEDO-33220, Revision 2. Based on the applicant’s response and DCD revisions, RAI 18.4-25 is resolved.

DCD Tier 2, Revision 9, Section 18.4.1 discusses the FRA IP. This provides a reasonable, high-level discussion of the FRA, which NEDO-33219, Revision 4, describes in more detail. DCD Tier 2, Revision 9, Section 18.4.2 discusses the FA IP. This provides a reasonable, high-level discussion of the FA, which NEDO-33220, Revision 4, describes in more detail.

DCD Tier 2, Revision 9, Section 18.4.4 references the detailed IPs (NEDO-33219, Revision 4; NEDE-33220P, Revision 4; and NEDO-33220, Revision 4), which are all designated as Tier 2*. As discussed above, NEDO-33219, Revision 4, and NEDO-33220, Revision 4, describe the FRA and FA program, which address the NUREG–0711 criteria for FRA and FA. Thus, Tier 2, together with the IPs, provides an acceptable description of the ESBWR FRA and FA programs.

18.4.4 Conclusions

The staff reviewed the FRA and FA at an IP level (see Section 18.4.1 of this report for a discussion of review levels) using the review criteria in Section 4.4 of NUREG–0711. For the reasons set forth above, the staff concludes that the FRA and FA programs for the ESBWR have: (1) defined the plant functions that are relied upon to satisfy plant safety objectives, and (2) allocated those functions to human and system resources in a way that takes advantage of human strengths and avoids human limitations. DCD Tier 1, Revision 9, Section 3.3, provides ITAAC sufficient to confirm that the FRA and FA are completed in accordance with the IPs (NEDO-33219, Revision 4, and NEDE-33220P, Revision 4), which the staff has reviewed and approved. Accordingly, the staff concludes that the applicant’s FRA and FA are acceptable at the IP level.

18.5 Task Analysis

18.5.1 Regulatory Criteria

The objective of reviewing task analysis is to verify that the applicant's task analysis identifies the specific tasks that are needed for function accomplishment and their information, control, and task-support requirements.

To review the applicant's task analysis plan, the staff used the review criteria in NUREG-0711, Section 5.4.

18.5.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.5, describes the ESBWR task analysis. DCD Tier 2, Revision 9, Section 18.5, incorporates by reference NEDE-33217P, Revision 6, and NEDO-33221, Revision 4, "ESBWR HFE Task Analysis Implementation Plan."

The staff also reviewed the following ESBWR documents:

- GEH responses to RAIs 18.5-1 through 18.5-40
- ESBWR DCD Tier 1, Revision 9, Section 3.3
- ESBWR DCD Tier 2, Revision 9, Chapter 19
- NEDO-33201, Revision 6

In addition to reviewing the applicant's design documents, the staff conducted a regulatory audit in January and July 2007, to examine the initial application of the processes described in these documents to the ESBWR design and to evaluate the documentation of the results. Following design certification, the staff will need to verify the final results of the design analyses, either in the COL application or through the ITAAC process, to ensure that the design was completed in accordance with the process specified in the design certification, as reflected in the DAC.

18.5.3 Staff Evaluation

The staff performed an IP level of review as described in NUREG-0711 and Section 18.1 of this report. This section presents the applicable review criteria from NUREG-0711 (reproduced below) followed by an evaluation of each criterion. In addition, this section also addresses related documents (i.e., DCD Tier 1 and Tier 2 information).

18.5.3.1 *NUREG-0711 Review Criteria*

NUREG-0711 includes seven criteria for this topic. However, the seventh criterion relates to plant modifications and is not applicable to new plant designs.

(1) The scope of the task analysis should include:

- Selected representative and important tasks from the areas of operations, maintenance, test, inspection, and surveillance
- Full range of plant operating modes, including startup, normal operations, abnormal and emergency operations, transient conditions, and low-power and shutdown conditions

- HAs that have been found to affect plant risk by means of PRA importance and sensitivity analyses should also be considered risk-important. Internal and external initiating events and actions affecting the PRA Level I and II analyses should be considered when identifying risk-important actions
- Where critical functions are automated, the analyses should consider all human tasks including monitoring of the automated system and execution of backup actions if the system fails.

Evaluation of Criterion (1)

The applicant operational analyses include FRA, FA, and task analysis. These analyses are performed in an iterative, top-down fashion. NEDO-33221, Revision 4, establishes a scope for task analysis that includes a comprehensive range of tasks. Section 1.2 states that the analyses address the following:

- Startup
- Normal operations
- Abnormal and emergency operations
- Transient conditions
- Low power operation
- Shutdown conditions

In addition, the plan's scope includes:

- Operation support during periods of maintenance and tests of plant systems and equipment, including HSI equipment
- Evaluation of tasks that are risk important as determined by the HRA/PRA
- Identification of minimum inventory HSIs

The Task Analysis Plan scope includes important tasks, the full range of plant operating modes, risk-important HAs, and critical automated functions, as described in detail above. Accordingly, the staff finds the Task Analysis Plan's treatment of the criterion for scope acceptable.

- (2) Tasks should be linked using a technique such as operational sequence diagrams. Task analyses should begin on a gross level and involve the development of detailed narrative descriptions of what personnel have to do. The analyses should define the nature of the input, process, and output needed by and of personnel. Detailed task descriptions should address (as appropriate) the topics listed in Table 5.1 of NUREG-0711.

Evaluation of Criterion (2)

In RAIs 18.5-5 and 18.5-19, the staff identified that the applicant's proposed task analysis methodology needed to (1) provide step-by-step, specific guidance on how to perform the task analysis, (2) clarify that the methodology was an actual plan for performing a task analysis rather than a compilation of recommended practices, (3) clarify task analysis methods, and (4) define risk-important HAs. As documented through several supplemental RAIs, the staff determined that the necessary level of detail was in the applicant's internal work instructions and needed to be incorporated into the IPs, NEDO-33221 and NEDO-33217. RAIs 18.5-5

and 18.5-19 were being tracked as open items in the SER with open items. In response, the applicant provided the information at a level of detail sufficient for the staff to complete its review of the task analysis methodology and incorporated this information into the appropriate IPs. The staff evaluation of the IP, as updated through the RAI responses, is described below. Based on the applicant's responses and NEDE-33221P and NEDE-33217P revisions, RAIs 18.5-5 and 18.5-19 are resolved.

NEDO-33221, Revision 4, Sections 4.1 and 4.2, provide an overview of the ESBWR task analysis methodology for system-level analyses and plant-level analyses, respectively. Appendices B and C of NEDE-33221P, Revision 4, describes the methodology for each analysis in detail. Sections 4.1 and 4.2 identify the inputs to the task analyses and include the results of the FRA, FA, and identification of risk-important actions.

NEDO-33221, Revision 4, Sections 4.1.3 and 4.2.3, provide an overview of the process to be used by task analysts. Appendices B, and C of NEDE-33221P, Revision 4, describe the process in step-by-step detail. The process includes steps for identifying tasks, sequencing tasks in a logical order, identifying design elements required for task completion (discussed further below), and identifying operating instructions and procedures. While the specific processes differ slightly, depending on whether the analyses are conducted for plant-level or system-level tasks, the methodology is largely consistent. High-level task descriptions, or narratives, are developed and analyzed until task performance elements and task termination criteria are identified.

NEDO-33221, Revision 4, Sections 4.1.4 and 4.2.4, list the outputs of the task analysis. The outputs include the types of considerations identified in NUREG-0711, Table 5.1. NEDE-33221P, Revision 4, provides proprietary information describing the administrative controls and methodology for performing the task analysis, which are evaluated in the proprietary SER. In general, the task analysis methodology includes step-by-step direction for addressing the considerations identified in the NUREG-0711, Table 5.1.

Accordingly, the staff finds the Task Analysis Plan's treatment of the criterion for task analysis methods acceptable.

- (3) The task analysis should be iterative and become progressively more detailed over the design cycle. It should be detailed enough to identify information and control requirements to enable specification of detailed requirements for alarms, displays, data processing, and controls for human task accomplishment.

Evaluation of Criterion (3)

The methodology presented is an iterative analysis leading to task requirements for HSI design. NEDO-33221, Revision 4, page 1, states that the operations analyses, including FRA, allocation of function, and task analysis, "is an iterative integration of the three elements of functional requirements, FA, and task analysis to establish requirements for the HSI design." NEDE-33221P, Revision 4, Appendices B and C, provide detailed steps for identifying task design elements, including alarms, displays, data processing, and controls, for system-level and plant-level task analysis, respectively. The staff evaluated the level of detail of the task analysis and the associated design elements identified during the July 2007 regulatory audit. The sample results examined provided a comprehensive decomposition of tasks to the point at which individual HSI requirements, including alarms, indications, controls, and communications, were identified. Moreover, the regulatory audit confirmed that NEDO-33221P, Revision 4 outlines the

appropriate steps for identifying the task related design elements at an acceptable level of detail. Accordingly, the staff finds the Task Analysis Plan's treatment of the criterion for iterative analysis acceptable.

(4) The task analysis should address issues such as:

- The number of crew members
- Crew member skills
- Allocation of monitoring and control tasks to the (a) formation of a meaningful job and (b) management of crew member's physical and cognitive workload

Evaluation of Criterion (4)

In RAI 18.5-26, the staff identified that the level of detail describing the workload analysis was insufficient in terms of (1) describing the integration of all tasks into a specific job; (2) providing information regarding workload assessments to list considerations such as workload, crew member skills, and work allocation; and (3) describing the means to evaluate workload. As documented through several supplemental RAIs, the staff determined that the necessary level of detail was in the applicant's internal work instructions and needed to be incorporated into the IP, NEDO-33221. RAI 18.5-26 was being tracked as open item in the SER with open items. In response, the applicant provided the information at a level of detail sufficient for the staff to complete its review of the workload analysis methodology and incorporated this information into the appropriate IP, particularly in Appendix A to NEDE-33221P. The staff evaluation of the IP, as updated through the RAI responses, is described below. Based on the applicant's responses and NEDE-33221P revisions, RAI 18.5-26 is resolved.

NEDE-33221P, Revision 4, Sections 4.1.3.6 and 4.2.3.6, address crew numbers, skills, and the allocation of tasks to form meaningful jobs for system-level analyses and plant-level analyses, respectively. Workload analyses, including both physical and cognitive workload, are used as the primary basis for work distribution. Appendix A, "Workload Analysis Process," to NEDE-33221P, Revision 4, describes the detailed, proprietary methodology. The proprietary SER provides additional detail on how the process used conforms to the NUREG criterion. In general the process is specific and has appropriate interfaces with other parts of the HFE design process. The workload analysis results are applied and the numbers of personnel needed for task performance and their requisite skills are specified during the detailed system-level and plant-level task analyses described in NEDE-33221P, Revision 4, Appendices B and C, respectively.

Accordingly, the staff finds the Task Analysis Plan's treatment of the criterion for task analysis issues acceptable.

(5) The task analysis results should be used to define a minimum inventory of alarms, displays, and controls necessary to perform crew tasks based on both task and instrumentation and control requirements.

Evaluation of Criterion (5)

In RAI 18.5-27, the staff requested that the applicant explain how Minimum Inventory is identified and what criteria are used in the selection process. As documented through several supplemental RAIs, the staff determined that the DCD needed to include the Minimum Inventory and the process to develop it. RAI 18.5-27 was being tracked as an open item in the SER with

open items. In the applicant's response to RAI 18.5-27 and related RAIs, the applicant revised DCD Tier 2, Revision 6, Section 18.5.1, to describe the process used to determine Minimum Inventory and included the Minimum Inventory in DCD Tier 2, Revision 6, Tables 18.1-1a and 18.1-1b. The staff evaluates Minimum Inventory and its development as set forth in Section 18.14 of this report and finds it acceptable. Based on the applicant's response and DCD revisions, RAI 18.5-27 is resolved.

- (6) The task analysis results should provide input to the design of HSIs, procedures, and personnel training programs.

Evaluation of Criterion (6)

NEDO-33221, Revision 4, Sections 4.1.4 and 4.2.4, identify system-level task analysis and plant-level task analysis outputs, respectively, for HSIs, procedures, and training program design. NEDO-33221, Revision 4, Figure 3, depicts the relationship between these two sections. The staff evaluated the suitability of the task analyses to support these later design activities during the July 2007 regulatory audit. The sample results illustrated the analysis and break down of high-level functions into the detailed tasks needed to accomplish these functions. These tasks were decomposed into discrete steps that provide a suitable input to procedure development. In fact, the methodology is structured in a way that procedures can be developed directly from the task analysis itself. The availability of results using this format provides detailed input to training development as well. Furthermore, as noted in the discussion of Criterion (3), the HSI requirements for task step completion are defined. Thus, the task analysis methodology provides comprehensive and detailed input to the development of HSIs, procedures, and training program development. Accordingly, the staff finds the Task Analysis Plan's treatment of the criterion for task analysis input to other HFE elements acceptable.

18.5.3.2 Relationship to Other Documents

18.5.3.2.1 DCD Tier 1, Section 3.3, "Human Factors Engineering"

DCD Tier 1, Revision 9, Table 3.3-2, contains the Tier 1 ITAAC developed by the applicant for HFE. Table 3.3-2 contains 10 items, one for each element of NUREG-0711 (except HFE program management, procedures and training) plus one item that addresses integrated system validation scenarios. Each item in Table 3.3-2 is linked to the corresponding ESBWR element IP. As described in Section 14.3.9 of this report, DCD Tier 1, Section 3.3, provides ITAAC sufficient to confirm that applicable HFE elements are completed in accordance with their respective IPs, which includes confirming that the task analysis is completed in accordance with the IP (NEDE-33221P, Revision 4), which the staff has reviewed and approved.

18.5.3.2.2 DCD Tier 2, Section 18.5, "Task Analysis"

In RAI 18.5-30, the staff identified that the task analysis methodology presented in NEDO-33221, Revision 1, was not consistent with the methodology summarized in DCD Tier 2, Revision 3, Section 18.5. For example, the IP discusses two major levels of analysis - plant and system - while the DCD did not. RAI 18.5-30 was being tracked as an open item in the SER with open items. In its response, the applicant explained that while different terminology is used, the DCD Tier 2, Chapter 18, identifies both plant-level and system-level analyses. In addition, the applicant rewrote DCD Tier 2, Revision 5, Section 18.5 to address the staff's concerns. As described below, the staff finds the revised Section 18.5 acceptable. Based on the applicant's response and revisions to the DCD, RAI 18.5-30 is resolved.

DCD Tier 2, Revision 9, Section 18.5, provides a high-level description of the ESBWR task analysis that ensures that the applicant's task analysis identifies the specific tasks that are needed for function accomplishment and the information and design elements needed for task accomplishment. This section of the DCD also references the detailed IP (NEDE-33221P, Revision 4), and is designated as Tier 2*. As discussed above, NEDE-33221P, Revision 4, describes a task analysis methodology which addresses the NUREG-0711 criteria for task analysis. Thus, Tier 2, together with the referenced IP, provides an acceptable description of the ESBWR task analysis.

18.5.4 Conclusions

The staff reviewed the task analysis at an IP level (see Section 18.1.4 of this report for a discussion of review levels) using the review criteria in Section 5.4 of NUREG-0711. The staff concludes that the ESBWR task analysis, as described in NEDE-33221P, Revision 4, provides an acceptable methodology for analyzing the number and qualifications of personnel in a systematic manner that demonstrates a thorough understanding of operational functions and tasks. DCD Tier 1, Revision 9, Section 3.3, provides ITAAC sufficient to confirm that the task analysis is completed in accordance with the IP (NEDE-33221P, Revision 4), which the staff has reviewed and approved. Accordingly, the staff concludes that the applicant's task analysis is acceptable at the IP level.

18.6 Staffing and Qualifications

18.6.1 Regulatory Criteria

The objective of reviewing staffing and qualifications is to verify that the applicant has systematically analyzed the need for the number and qualifications of personnel and has demonstrated a thorough understanding of task requirements and regulatory requirements.

The NUREG-0711 criteria addressing staffing and qualification have a small overlap with the SRP Section 13.1 which addresses plant staff organization. The overlap is limited to verifying 10 CFR 50.54(m) is met. In accordance with SRP Chapter 13, the staff evaluates plant staff organization as an operational program. In SRP Chapter 18, the staff evaluates staffing and qualifications as input to the HFE design. Initial staffing levels and qualifications may be assumed but the analysis completed as part of the HFE design verifies that these assumptions are correct for the full range of plant conditions and operating tasks. This HFE analysis is not addressed in the operational program element of SRP Chapter 13.1. Consequently, use of an ITAAC to assess the completed design product is appropriate.

To review the applicant's staffing and qualifications plan, the staff used the review criteria in NUREG-0711, Section 6.4.

18.6.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.6 describes the ESBWR staffing and qualifications. DCD Tier 2, Revision 9, Section 18.6, incorporates by reference NEDE-33217P, Revision 6, and NEDO-33266, Revision 3, "ESBWR Human Factors Engineering Staffing and Qualifications Implementation Plan, May 2008."

The staff also reviewed the following ESBWR documents:

- ESBWR DCD Tier 1, Revision 9, Section 3.3
- ESBWR DCD Tier 2, Revision 9, Chapter 19
- NEDO-33201, Revision 6
- GEH response to RAls 18.6-1 through 18.6-10
- GEH ESBWR Baseline Record Review (BRR), Draft 1A, January 2007, (audited material)
- GEH ABWR FOAKE Plant Staffing Evaluation, Revision 0, May 24, 1996, (audited material)

18.6.3 Staff Evaluation

The staff performed an IP level of review as described in NUREG-0711 and Section 18.1 of this report. This section presents the applicable review criteria from NUREG-0711 (reproduced below) followed by an evaluation of each criterion. In addition, this section also addresses related documents (i.e., DCD Tier 1 and Tier 2 information).

18.6.3.1 NUREG-0711 Review Criteria

NUREG-0711 includes four criteria for this topic, as described below.

- (1) Staffing and qualifications should address applicable guidance in SRP Section 13.1 and 10 CFR 50.54.

Evaluation of Criterion (1)

NEDO-33266, Revision 3, Section 3.2, Table 1, specifies the initial baseline shift staffing and qualifications for the ESBWR. This includes two senior reactor operators (SROs) (the shift manager and the CR supervisor), two reactor operators, and two auxiliary operators. This satisfies the minimum requirements specified in 10 CFR 50.54(m)(2)(i) for a single-unit nuclear power plant. DCD Tier 2, Revision 9, Section 18.6.2, Section 18.6.3, and Table 18.6-1, also specify the ESBWR initial baseline staffing assumptions, which are the same as those in the plan. The staff finds this acceptable.

DCD Tier 2, Revision 9, Chapter 13 addresses the other aspects of 10 CFR 50.54(i) through 10 CFR 50.54(m) (e.g., requirements for an operator at the controls). DCD Tier 2, Revision 9, Section 13.1.1, identifies COL Item 13.1.1-A, which states that the COL applicant referencing the ESBWR will submit documentation that demonstrates that its organizational structure is consistent with the ESBWR HFE design requirements and complies with the requirements of 10 CFR 50.54(i) through 10 CFR 50.54(m). The staff finds this COL information item acceptable since it identifies that the COL needs to address the remaining aspects of this criterion. Accordingly, the staff finds the Staffing and Qualifications Plan's treatment of the criterion for SRP Section 13.1 and the requirements of 10 CFR 50.54 acceptable.

- (2) The staffing analysis should determine the number and background of personnel for the full range of plant conditions and tasks including operational tasks (normal, abnormal, and emergency), plant maintenance, and plant surveillance and testing. The scope of personnel that should be considered is identified in the HFE Program Management element (see Section 2.4.1, Criterion 5).

Evaluation of Criterion (2)

NEDO-33266, Revision 3, Section 1.2, specifies that the staffing analyses address activities during normal power operation, as well as during transient and accident events included in the

plant design basis. Section 1.3.1 of the plan defines transient events as initiating events that can result in emergency conditions requiring prompt operator actions to avoid damage or accidents that damage structures, systems, or components (SSCs).

The plant staff must carry out tasks related to qualification, repair, maintenance, recordkeeping, configuration control, monitoring, surveillance, and testing of plant equipment during startup, normal operations, abnormal operations, transient conditions, low power, and shutdown conditions. NEDO-33266, Revision 3, Section 1.2, also identifies the applicable plant personnel addressed by the HFE program, including licensed CR operators, nonlicensed operators, shift supervisor, shift technical advisor, instrument and control technicians, electrical and mechanical maintenance personnel, radiological protection technicians, chemistry technicians, and engineering support personnel. In addition, any other plant personnel who perform tasks that are directly related to plant safety are addressed. This includes all of the personnel identified in the HFE program management element of NUREG-0711, Section 2.4.1, Criterion (5).

The Staffing and Qualifications Plan identifies the number and background of personnel for the full range of plant conditions and tasks as described in detail above. Accordingly, the staff finds the Staffing and Qualifications Plan's treatment of the criterion for number and background of personnel acceptable.

- (3) The staffing analysis should be iterative; that is, initial staffing goals should be reviewed and modified as the analyses associated with other elements are completed.

Evaluation of Criterion (3)

NEDO-33266, Revision 3, Figures 1 and 2, illustrate the staffing analysis process, including how it depends on, and interfaces with, the other HFE program elements. Table 1 of the plan shows the preliminary operational staffing assumptions for reactor control and monitoring. Figures 1 and 2 illustrate the feedback loops and possible modification of staffing and qualifications as the various elements are completed. This includes blocks for OER, FRA, FA, task analysis, HRA/PRA, and procedures and training. Sections 3 and 4 describe these processes both graphically and narratively. Section 3.1 states the following:

The number of qualified staff for the ESBWR must be adequate to provide safe operation under design basis and risk important accident conditions. To meet this goal, consideration is given to the numbers and functions of the staff needed to safely perform all required plant operations, maintenance, and technical support for each operational mode...

Sections 3 and 4 provide details on how this is accomplished.

The Staffing and Qualifications Plan is iterative in that it includes reviewing and modifying the initial staffing goal as other analyses are completed as described in detail above. Accordingly, the staff finds the Staffing and Qualifications Plan's treatment of the criterion for an iterative analysis acceptable.

- (4) The basis for staffing and qualifications should be modified to address these issues:
 - Operating Experience Review
 - Operational problems and strengths that resulted from staffing levels in predecessor systems

- Initial staffing goals and their bases including staffing levels of predecessor systems and a description of significant similarities and differences between predecessor and current systems
- Staffing considerations described in NRC IN 95-48, “Results of Shift Staffing Study”
- Staffing considerations described in NRC IN 97-78, “Crediting of Operator Actions in Place of Automatic Actions and Modifications of Operator Actions, Including Response Times”
- Functional Requirements Analysis and Function Allocation
 - Mismatches between functions allocated to personnel and their qualifications
 - Changes the roles of personnel due to plant system and HFE modifications
- Task Analysis
 - The knowledge, skills, and abilities needed for personnel tasks addressed by the task analysis
 - Personnel response time and workload
 - Personnel communication and coordination, including interactions between them for diagnosis, planning, and control activities, and interactions between personnel for administrative, communications, and reporting activities
 - The job requirements that result from the sum of all tasks allocated to each individual both inside and outside the control room
 - Decreases in the ability of personnel to coordinate their work due to plant and HFE modifications
 - Availability of personnel considering other activities that may be ongoing and for which operators may take on responsibilities outside the control room (e.g., fire brigade)
 - Actions identified in 10 CFR 50.47; NUREG–0654, Revision 1, “Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants;” and procedures to meet an initial accident response in key functional areas as identified in the emergency plan
 - Staffing considerations described by the application of ANSI/ANS 58.8-1994, “Time Response Design Criteria for Safety-Related Operator Actions”
- Human Reliability Analysis
 - The effect of overall staffing levels on plant safety and reliability
 - The effect of overall staffing levels and crew coordination for risk-important HAs
 - The effect of overall staffing levels and the coordination of personnel on human errors associated with the use of advanced technology
- HSI Design
 - Staffing demands resulting from the locations and use (especially concurrent use) of controls and displays
 - Coordinated actions between individuals

- Decreases [in] the availability or accessibility of information needed by personnel due to plant system and HFE modifications
- The physical configuration of the control room and control consoles
- The availability of plant information from individual workstations and group-view interfaces
- Procedure Development
 - Staffing demands resulting from requirements for concurrent use of multiple procedures
 - Personnel skills, knowledge, abilities, and authority identified in procedures
- Training Program Development
 - Crew coordination concerns that are identified during the development of training

Evaluation of Criterion (4)

As noted under Criterion (3) above, NEDO-33266, Revision 3, ensures that the basis for staffing and qualification includes consideration of OER, FRA, FA, task analysis, HRA/PRA, and procedures and training. A clear link exists between HSI design and the staffing and qualifications defined in the program. The plan includes an initial baseline staffing and qualifications level based on OER from the BWR and ABWR reference plants. A second phase comprises a deterministic analysis that considers the deterministic rules established in the regulations and lessons learned from worldwide operating experience of all reactors, with a focus on BWRs. This phase also considers the SFRA, FA, and task analysis. Phase 3 uses the insight from the HRA/PRA and incorporates feedback in both the staffing analysis and the HRA/PRA. Phase 4 includes screening the various tasks to determine if they are to be performed by the normal crew or whether additional station personnel should be assigned.

Phase 5 determines whether the recommended staffing and qualifications are adequate to safely operate the ESBWR. This is accomplished by evaluating the interface between CR staff, the CR HFE design elements and plant procedures. Part of this evaluation occurs during the HFE V&V program. Further reviews take place as part of the training program development. Section 4.6 of NEDO-33266 describes the phase 5 aspects related to verifying plant staffing and qualifications. Accordingly, the staff finds the Staffing and Qualifications Plan's treatment of the criterion for consideration of HFE program elements acceptable.

18.6.3.2 Relationship to Other Documents

18.6.3.2.1 DCD Tier 1, Section 3.3, "Human Factors Engineering"

DCD Tier 1, Revision 9, Table 3.3-2, Item 1, contains the Tier 1 ITAAC developed by the applicant for HFE. Table 3.3-2 contains 10 items, one for each element of NUREG-0711 (except HFE program management, procedures and training) plus one item that addresses integrated system validation scenarios. Each item in Table 3.3-2 is linked to the corresponding ESBWR element IP. As described in Section 14.3.9 of this report, DCD Tier 1, Section 3.3, provides ITAAC sufficient to confirm that applicable HFE elements are completed in accordance with their respective IPs, which includes confirming that plant staffing and qualifications are completed in accordance with the IP (NEDO-33266, Revision 3), which the staff has reviewed and approved.

18.6.3.2.2 DCD Tier 2, Section 18.6, “Staffing and Qualifications”

In RAI 18.6-13, the staff requested that the applicant correct the date for NEDO-33266, Revision 1, from March 2007 to January 2007 in DCD Tier 2, Section 18.6.8. In its response, the applicant stated that it would correct the date in DCD Tier 2, Revision 5, which the staff has confirmed. Based on the applicant’s response RAI 18.6-13 is resolved.

DCD Tier 2, Revision 9, provides a high-level description of the staffing and qualifications for the ESBWR, which includes the background, the objectives and scope of staffing and qualification analyses, the ESBWR baseline staffing assumptions, a discussion of the staffing and qualifications IP, and a summary of the methodology of the staffing and qualification analyses. This section of the DCD also references the detailed IP (NEDO-33266, Revision 3), which is designated as Tier 2*. As discussed above, NEDO-33266, Revision 3 describes a staffing and qualification program that addresses the NUREG–0711 criteria for staffing and qualification. Thus, DCD Tier 2 together with the referenced IP provides an acceptable description of the ESBWR staffing and qualification program. Accordingly, the staff finds the DCD Tier 2, Revision 9, Chapter 18 treatment of staffing and qualifications acceptable.

18.6.4 Conclusions

The staff reviewed the ESBWR staffing and qualifications at an IP level (see Section 18.1.4 of this report for a discussion of review levels) using the review criteria in Section 6.4 of NUREG–0711. For reasons set forth above, the staff concludes that the ESBWR staffing and qualifications plan, as described in NEDO-33266, Revision 3, provides an acceptable methodology for analyzing the number and qualifications of personnel in a systematic manner which demonstrates a thorough understanding of operational tasks and applicable regulatory requirements. DCD Tier 1, Revision 9, Section 3.3, provides sufficient ITAAC to confirm that the staffing and qualifications are completed in accordance with the IP (NEDO-33266, Revision 3), which the staff has reviewed and approved. Accordingly, the staff concludes that the applicant’s staffing and qualifications are acceptable at the IP level.

18.7 Human Reliability Analysis

18.7.1 Regulatory Criteria

The objective of reviewing HRA integration is to verify that (1) the applicant has addressed human-error mechanisms in the design of the HFE aspects of the plant to minimize the likelihood of personnel error and to verify errors are detected and recovered from and (2) the HRA activity effectively integrates the HFE program and PRA and risk analysis.

To review the applicant’s human reliability analysis plan, the staff used the review criteria in NUREG–0711, Section 7.4.

18.7.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.7, describes the ESBWR HRA. DCD Tier 2, Revision 9, Section 18.7, incorporates by reference NEDE-33217P, Revision 6, and NEDO-33267, Revision 4, “ESBWR Human Factors Engineering Human Reliability Analysis Implementation Plan.”

The staff also reviewed the following ESBWR documents:

- ESBWR DCD Tier 1, Revision 9, Section 3.3
- ESBWR DCD Tier 2, Revision 9, Chapter 19
- NEDO-33201, Revision 6
- GEH responses to RAIs 18.7-1 through 18.7-16 GEH letter, "Submittal of ESBWR DCD Chapter 18, Human Factors Engineering—RAI to DCD Roadmap Document," June 27, 2007
- NEDO-33411, "Risk Significance of Structures, Systems and Components for the Design Phase of the ESBWR," Revision 0

18.7.3 Staff Evaluation

The staff performed an IP level of review as described in NUREG-0711 and Section 18.1 of this report. This section presents the applicable review criteria from NUREG-0711 (reproduced below) followed by an evaluation of each criterion. In addition, this section also addresses related documents (i.e., DCD Tier 1 and Tier 2 information).

18.7.3.1 NUREG-0711 Review Criteria

NUREG-0711 includes four criteria for this topic.

- (1) Risk-important HAs should be identified from the PRA/HRA and used as input to the HFE design effort. These actions should be developed from the Level 1 (core damage) PRA and Level 2 (release from containment) PRA including both internal and external events. They should be developed using selected (more than one) importance measures and HRA sensitivity analyses to provide reasonable assurance that an important action is not overlooked because of the selection of the measure or the use of a particular assumption in the analysis.

Evaluation of Criterion (1)

In three related RAIs (RAIs 18.7-7, 18.7-8, and 18.7-9) the staff requested that the applicant clarify the list of risk-important HAs, the criteria for determining the risk-important HAs, and the PRA inputs used to determine the risk-important HAs. RAIs 18.7-7, 18.7-8, and 18.7-9 were being tracked as open items in the SER with open items. Through responses to multiple supplemental RAIs, the applicant provided information sufficient for the staff to complete its review of the risk-important HA criteria. The applicant incorporated this information on risk-important HAs into DCD Tier 2, Section 18.7, and NEDO-33267. The staff evaluation of DCD Tier 2, Revision 9, Section 18.7; NEDO-33267; and NEDO-33201, as updated through the RAI responses, is described below. Based on the applicant's responses and document revisions, RAIs 18.7-7, 18.7-8, and 18.7-9 are resolved. Some additional modification to the treatment of risk-important HAs in NEDO-33267 resulted from RAI 18.7-16, as discussed below. These modifications were necessary to address inconsistencies between NEDO-33267, Revision 3, and the ESBWR PRA (NEDO-33201).

DCD Tier 2, Revision 9, Section 18.7.1, provides the scope for using HRA in HFE activities. NEDO-33267, Revision 4, provides a well-detailed overview of the HRA and its integration with the design of the ESBWR and the HFE program. The report provides the purpose and scope of the plan and its high-level elements or aspects. It explains how the HRA is performed iteratively

and how the analysis interacts with the various aspects of the HFE program. NEDO-33267, Revision 4, also provides an overview of the HRA methodology itself and its relationship to the PRA.

NEDO-33267, Revision 4, Section 1.2, states that the scope of the plan includes developing a process for using HRA/PRA (e.g., Level 1, Level 2, internal and external events) to support the design of the ESBWR HSI. DCD Tier 2, Revision 9, Section 18.7.2, states that the process for determining the risk-important HAs includes the use of Level 1, Level 2, internal and external events, and the low power and shutdown PRA. NEDO-33267, Revision 4, defines a HA as a manual response to achieve one task or objective and a human interaction as a set of HAs or a single HA. Section 3.2.1.1 further states that each individual PRA model for core damage frequency (CDF) and large release fraction (LRF) are used to evaluate human interaction importance. Each PRA importance measure is applied to the top event of all PRA submodels (i.e., CDF for Level 1 internal events, LRF for Level 2); all external events, such as fire and flooding; and the shutdown PRA. The importance of each modeled human interaction is measured using risk achievement worth (RAW) and Fussell-Vesely (FV) at each stage of PRA development.

Either HAs or human interactions can be represented as a basic event in a PRA fault tree or as a branch point in the PRA event tree. NEDO-33267, Section 3.2.1 states that the ranking of human interaction tasks will use the risk importance measures of RAW and FV. Section 3.2.1.1 states that the ESBWR PRA first identifies potentially risk-important human interactions and that a goal of the HRA and HFE analyses is to keep the quantitative risk importance of these potentially risk-important actions as low as practical.

For the purpose of HRA and HFE, the applicant initially classified human interactions with an FV value greater than 0.1 and a RAW greater than 2.0 as important to risk. These are typical and acceptable criteria, but the staff noted that these criteria were inconsistent with those in Chapter 17 of the ESBWR PRA (NEDO-33201, Revision 5), which classifies risk-significant actions using values of FV greater than 0.01 and RAW greater than 5.0. In addition, the Design Reliability Assurance Program, described in DCD Tier 2, Section 17.4, used thresholds similar to those in the PRA to determine risk-significant SSCs. In RAI 18.7-16, the staff requested that the applicant address this discrepancy.

In response, the applicant proposed to revise the risk thresholds for the HFE program to agree with those of the PRA. They provided markups of the HRA IP and DCD Tier 2, Chapter 19 that illustrated the changes. The risk-important thresholds are an FV value greater than or equal to 0.01 or a RAW value greater than or equal to 5.0. The staff finds that the RAI response and DCD changes were acceptable because these changes result in the use of consistent criteria for risk-important HA across the applicant's HRA-related documents. The staff notes that both sets of threshold criteria result in the same number of risk important HAs. The staff confirmed the implementation of these changes in NEDO-33267, Revision 4 (the HRA IP). Based on the applicant's response, RAI 18.7-16 is resolved.

Chapter 17 of the ESBWR PRA (NEDO-33201, Revision 6) documents the RAW and FV values of all the HAs in the various portions of the PRA and orders them by each of the importance values. Tables 17.7-1 through 17.7-24 contain this information. Table 17.1-3 summarizes the 39 risk-important HAs that exceed the thresholds; these HAs have not changed with the revised thresholds. Additionally, all of the operator actions listed within the tables of Section 17.7 will be included as inputs to the HFE program.

The DCD, Revision 9, and NEDO-33267, Revision 4 are sufficient to define the set of criteria to be used for determining the risk-important HAs for the ESBWR. Accordingly, the staff finds the HRA Plan's treatment of the criterion for risk-important HAs acceptable.

- (2) Risk-important HAs and their associated tasks and scenarios should be specifically addressed during function allocation analyses, task analyses, HSI design, procedure development, and training. This will help verify that these tasks are well supported by the design and within acceptable human performance capabilities (e.g., within time and workload requirements).

Evaluation of Criterion (2)

NEDO-33267, Revision 4, Section 3.3, "Application to the ESBWR," states that these relative risk-important human interactions from the HRA/PRA will be used as input to the HFE program (i.e., to support function allocation analyses, task analyses, HSI design, procedure development, and training). This section further notes that the design effort demonstrates how these HA tasks are well supported by the HSI design and that suitable crew members and sufficient time are available to accomplish the action given that the need is detected. Section 4.2 notes that the HRA/PRA information is used to help prioritize maintenance tasks. Accordingly, the staff finds the HRA Plan's treatment of the criterion for use of HRA results in other HFE elements acceptable.

- (3) The use of PRA/HRA results by the HFE design team should be specifically addressed; that is, how are risk-important HAs addressed (through HSI design, procedural development, and training) under the HFE program to minimize the likelihood of operator error and provide for error detection and recovery capability.

Evaluation of Criterion (3)

NEDO-33267, Revision 4, Section 3.3, states that HA tasks are analyzed with an emphasis on human error mechanisms. This will minimize the likelihood of operator error for risk-important HAs by first identifying key human-error mechanisms and then providing means for error detection and recovery capability within the HSI design, procedures, and training elements under the HFE program. Section 3.3 provides examples of how the PRA, HRA, and HFE design processes evaluate human interactions and provide the means necessary to ensure that (1) the human tasks are well supported by the HSI design, (2) sufficient crew members are available, and (3) sufficient time is available to accomplish the actions. Section 4.3.1 notes that, by using importance rankings from the ESBWR PRA, insights are developed for HAs that need attention during design and operation. Where necessary, the HRA/PRA recovery actions are modeled (see discussion in NEDO-33267, Section 4.4.3) and any that are risk important are identified. These risk-important recovery actions are then processed through the HFE program to provide the HFE support needed to reliably perform the actions. Accordingly, the staff finds the HRA Plan's treatment of the criterion for use of HRA results for error detection and recovery acceptable.

- (4) HRA assumptions such as decision making and diagnosis strategies for dominant sequences should be validated by walkthrough analyses with personnel with operational experience using a plant-specific control room mockup or simulator. Reviews should be conducted before the final quantification stage of the PRA.

Evaluation of Criterion (4)

Several sections of NEDO-33267, Revision 4, address this criterion. Section 3.1 states that the HRA task interacts with the HFE V&V program to provide test scenarios and update quantitative evaluations based on data from the validation process. Section 3.3 notes that a variety of HRA assumptions are validated by using experienced crews with simulation and talk-through analyses. Section 4.3.3 states that HRA assumptions, risk-important HAs involving diagnosis, decision-making, planning, and implementation strategies during accident responses are validated by techniques such as event simulations or talk through analyses. Personnel with operating experience participate in these exercises. Section 4.4 states that items listed as assumptions for HRA quantification are confirmed during initial part-task simulations and during the V&V. Thus, the HRA IP provides commitments and details sufficient to ensure that HRA assumptions will be validated as part of the HSI design and validation process. Accordingly, the staff finds the HRA Plan's treatment of the criterion for validation of HRA assumptions acceptable.

18.7.3.2 Relationship to Other Documents

18.7.3.2.1 DCD Tier 1, Section 3.3, "Human Factors Engineering"

DCD Tier 1, Revision 9, Table 3.3-2, contains 10 items, one for each element of NUREG-0711 (except HFE program management, procedures and training) plus one item that addresses integrated system validation scenarios. Each item in Table 3.3-2 is linked to the corresponding ESBWR element IP. As described in Section 14.3.9 of this report, DCD Tier 1, Section 3.3, provides sufficient ITAAC to confirm that applicable HFE elements are completed in accordance with their respective IPs, which includes confirming that the HRA integration is completed in accordance with the IP (NEDO-33267, Revision 4), which the staff has reviewed and approved.

18.7.3.2.2 DCD Tier 2, Section 18.7, "Human Reliability Analysis"

DCD Tier 2, Revision 9, provides a high-level description of the HRA integration activities for the ESBWR that includes the objectives, scope, and methodology for using the HRA/PRA in HFE activities. This section of the DCD also references the detailed IP, NEDO-33267, Revision 4, which is designated as Tier 2*. As discussed above, NEDO-33267, Revision 4 describes an HRA integration program that conforms to the NUREG-0711 criteria for HRA. Thus, DCD Tier 2, Revision 9, Chapter 18, together with the referenced IP provides an acceptable description of the ESBWR HRA integration program. Accordingly, the staff finds the DCD Tier 2, Revision 9, Chapter 18 treatment of HRA acceptable.

18.7.4 Conclusions

The staff reviewed the ESBWR HRA integration at an IP level (see Section 18.1.4 of this report for a discussion of review levels) using the review criteria in Section 7.4 of NUREG-0711. For the reasons set forth above, the staff concludes that the HRA integration program, as described in NEDO-33267, Revision 4, provides an acceptable methodology to (1) address human-error mechanisms in the design of the HFE aspects of the plant to minimize the likelihood of personnel error and (2) verify that errors are detected and recovered from. This methodology also provides the means to ensure that the HRA activity effectively integrates the HFE program and HRA/PRA. DCD Tier 1, Revision 9, Section 3.3 provides ITAAC sufficient to confirm that the HRA integration is completed in accordance with the IP (NEDO-33267, Revision 4), which

the staff has reviewed and approved. Accordingly, the staff concludes that the applicant's HRA integration is acceptable at the IP level.

18.8 Human-System Interface Design

18.8.1 Regulatory Criteria

The objective of reviewing HSI design is to verify the process by which HSI design requirements are developed and HSI designs are identified and refined. The review should verify that the applicant has appropriately translated functional and task requirements to the detailed design of alarms, displays, controls, and other aspects of the HSI through the systematic application of HFE principles and criteria.

To review the applicant's HSI design plan, the staff used the review criteria in NUREG-0711, Section 8.4.

18.8.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.8, describes the ESBWR HSI design. DCD Tier 2, Revision 9, Section 18.8, incorporates by reference NEDE-33217P, Revision 6; NEDO-33268, Revision 5, "ESBWR Human-System Interface Design Implementation Plan"; and NEDE-33268P, Revision 5.

The staff also reviewed the following ESBWR documents:

- ESBWR DCD Tier 1, Revision 9, Section 3.3
- GEH responses to RAIs 18.8-1 through 18.8-59

18.8.3 Staff Evaluation

The staff performed an IP level review as described in NUREG-0711 and Section 18.1 of this report. This section presents the applicable review criteria from NUREG-0711 (reproduced below) followed by an evaluation of each criterion. In addition, this section also addresses related documents (i.e., DCD Tier 1 and Tier 2 information).

HSI design review topics include the following:

- HSI design inputs (four review criteria)
- concept of operations (one review criterion)
- functional requirement specification (three review criteria)
- HSI concept design (five review criteria)
- HSI detailed design and integration (10 review criteria)
- HSI tests and evaluations (two subtopics)
 - Tradeoff evaluations (two review criteria)
 - Performance-based tests (nine review criteria)
- HSI design documentation (two review criteria)

The staff reviewed the proposed SPDS using the requirements of 10 CFR 50.34(f)(2)(iv) and the criteria set forth in NUREG-0711 and Section 5 of NUREG-0700, "Human-System Interface Design Review Guidelines," issued May 2002. Although the HSI design can be considered a

part of the HSI detailed design and integration, the staff reviewed this topic in a separate section because of its importance and the existence of separate review criteria.

Moreover, in addition to reviewing the GEH design documents, the staff conducted regulatory audits in January and July, 2007, to examine the initial application of the processes described in these documents to the ESBWR design and to evaluate the documentation of the results. Following design certification, the staff will need to verify the final results of the design analyses, either in the COL application or through the ITAAC process, to ensure that the design was completed in accordance with the process specified in the design certification.

18.8.3.1 NUREG-0711 Review Criteria

There were nine RAI open items associated with multiple criteria in this section. The applicant has satisfactorily addressed them all, as described below. With the resolution of the RAIs, which in some cases resulted in significant changes to the IP, the applicant now has an IP that can be evaluated systematically using the NUREG-0711 criteria. Accordingly, only a brief summary of the previously open RAIs is presented to preserve the flow of the remainder of the evaluation against the individual NUREG-0711 criteria.

In RAI 18.8-2, the staff requested that the applicant provide step-by-step guidance on how to perform the HSI design in the HSI Design Plan. As documented through several supplemental RAIs, the staff determined that the necessary level of detail was in the applicant's internal work instructions and needed to be incorporated into the IP, NEDE-33268P. RAI 18.8-2 was being tracked as an open item in the SER with open items. In response, the applicant provided the information at a level of detail sufficient for the staff to complete its review of the HSI design criteria and incorporated this information into NEDE-33268P, Appendix A, Revision 5. The staff's evaluation of the IP, as updated through the RAI response, is described below. Based on the applicant's responses and the NEDE-33268P revisions, RAIs 18.8-2 is resolved.

In RAI 18.8-8, the staff requested that the applicant clarify the references to old documents that have been superseded by documents more applicable to modern technology. RAI 18.8-8 was being tracked as an open item in the SER with open items. In response, the applicant stated that it would reference the latest industry standards and delete references to obsolete standards. The staff then reviewed the references in NEDO-33268, Revision 3 and finds that the applicant referenced appropriate standards. Based on the applicant's response and the NEDO-33268 revision, RAI 18.8 is resolved.

In RAI 18.8-12, the staff requested that the applicant explain the item, "Expanding available information to cover implicit data," in a list of information processing functions in NEDO-33268 Section 4.3.4.16, Revision 0. In RAI response, the applicant indicated that it would remove the item. The staff finds that the applicant's response is acceptable since the subject item is not a necessary information processing function. Based on the applicant's response, RAI 18.8-12 is resolved in the SER with open items. RAI 18.8-12 was being tracked as a confirmatory item in the SER with open items. The staff verified that the item was removed in NEDO-33268, Revision 3 and the confirmatory item is closed.

In RAI 18.8-16, the staff requested clarification of (1) whether the ESBWR alarm response procedures will be computerized, and (2) a statement in NEDO-33268 that "an alarm is annunciated where the operator has the necessary means for initiating corrective actions." RAI 18.8-16 was being tracked as an open item in the SER with open items. Through multiple supplemental responses, the applicant clarified these statements and modified (1) NEDO-

33268, Section 4.1.4 Revision 2 to identify that online computer-based procedures are an output of the design process and (2) NEDO-33268, Section 4.3.4.11, Revision 3, item 3.c, to state that, “an alarm is presented as a visual and audible cue in close proximity to where the operator can take corrective action.” The staff finds that the applicant’s responses are acceptable because they clearly describe the strategy being used to communicate and respond to alarm conditions. This addresses NUREG–0711 guidance stating that the HSI design should be documented to include the detailed HSI description including its form, function and performance characteristics. Based on the applicant’s responses, RAI 18.8-16 is resolved

In RAI 18.8-17, the staff requested that the applicant clarify the source of anthropometric data used in HSI design. RAI 18.8-17 was being tracked as an open item in the SER with open items. Through multiple supplemental responses, the applicant clarified that it will use the anthropometric guidance from NUREG–0700 and will justify any deviations from NUREG–0700. The staff finds that the response is acceptable since NUREG–0700 is an appropriate source of anthropometric data. The staff verified that the applicant implemented the proposed changes in NEDO-33268, Revision 3. Based on the applicant’s responses and changes to NEDO-33268, RAI 18.8-17 is resolved.

In RAI 18.8-18, the staff requested that the applicant clarify ambiguous statements on the placement and the form of controls discussed in NEDO-33268, Section 4.3.4.9, Revision 0. RAI 18.8-18 was being tracked as an open item in the SER with open items. Through multiple supplemental responses, the applicant clarified that it would delete the statement on the placement of controls and modify the statement on the form of controls to state that the selection of the type of control is consistent with what the operator needs to navigate or take process control action and with the associated guidance provided in NUREG–0700. The staff finds that the response is acceptable since the meaning of these statements is now clear. NUREG–0700 is an appropriate source for guidance on selecting controller attributes. The staff verified that the applicant implemented the proposed changes in NEDO-33268, Revision 3. Based on the applicant’s responses and changes to NEDO-33268, RAI 18.8-18 is resolved.

In RAI 18.8-31, the staff requested that the applicant clarify overlapping and inconsistent descriptions of HSI design and evaluation tools, techniques, methods, and procedures throughout NEDO-33268, Revision 0. RAI 18.8-31 was being tracked as an open item in the SER with open items. Through multiple supplemental responses, the applicant clarified that it would include the same list of items in Sections 3.3.5.6 and 4.3.4.6 of NEDO-33268, Revision 3. The staff finds that the applicant’s responses are acceptable since the description of these design and evaluation are now internally consistent. The staff verified that the applicant implemented the proposed changes in NEDO-33268, Revision 3. Based on the applicant’s responses and changes to NEDO-33268, RAI 18.8-31 is resolved.

In RAI 18.8-32, the staff requested that the applicant clarify an ambiguous statement in NEDO-33268, Revision 0, regarding the criteria to be used in the selection of HSI design and evaluation tools. RAI 18.8-32 was being tracked as an open item in the SER with open items. Through multiple supplemental responses, the applicant clarified that checklists, drawings, mockups, and questionnaires and interviews would be used to gather HSI tests and evaluation data and information. The staff finds that the applicant’s responses are acceptable since the description of design selection and evaluation tools is now clear and is consistent. This appropriately addresses the NUREG–0711 guidance stating that the HSI design should be documented to include the detailed HSI description including its form, function and performance characteristics. The staff verified that the applicant implemented the proposed changes in

NEDO-33268, Revision 3. Based on the applicant's responses and changes to NEDO-33268, RAI 18.8-32 is resolved.

In RAI 18.8-43 and its supplement, the staff requested that the applicant describe aspects of the HSI plan as it relates to RG 1.22, "Periodic Testing of Protection System Actuation Functions (Safety Guide 22)"; RG 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems"; RG 1.62, "Manual Initiation of Protective Actions"; RG 1.97, "Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants"; RG 1.105, "Setpoints for Safety-Related Instrumentation"; and NUREG-0696, "Functional Criteria for Emergency Response Facilities." RAI 18.8-43 was being tracked as an open item in the SER with open items. In response to RAI 18.8-43 S01, the applicant added a discussion of these guidelines to NEDO-33268, Section 3.1.3, Revision 3. The staff finds that the applicant's response is acceptable. The HSI design IP now specifically addresses the criterion stating that applicable regulatory requirements should be identified as inputs to the HSI design process. The staff verified that the applicant implemented the proposed changes in NEDO-33268, Revision 3. Based on the applicant's responses and changes to NEDO-33268, RAI 18.8-43 is resolved.

18.8.3.1.1 Human-System Interface Design Inputs

NUREG-0711 identifies several sources of information that provide input to the HSI design process. The review criteria in this section identify these sources of information.

- (1) Analysis of Personnel Task Requirements - The analyses performed in earlier stages of the design process should be used to identify requirements for the HSIs. These analyses include:
 - Operational experience review—Lessons learned from other complex human-machine systems, especially predecessor designs and designs involving similar HSI technology should be used as an input to HSI design.
 - Functional requirement analysis and function allocation—The HSIs should support the operator's role in the plant, e.g., appropriate levels of automation and manual control.
 - Task analysis—The set of requirements to support the role of personnel is provided by task analysis. The task analysis should identify:
 - Tasks that are necessary to control the plant in a range of operating conditions for normal through accident conditions;
 - Detailed information and control requirements (e.g., requirements for display range, precision, accuracy, and units of measurement);
 - Task support requirements (e.g., special lighting and ventilation requirements); and
 - Risk-important HAs and their associated performance shaping factors, as identified through HRA should be given special attention in the HSI design process.
 - Staffing/qualifications and job analyses—The results of staffing/qualifications analyses should provide input for the layout of the overall control room and the allocation of controls and displays to individual consoles, panels, and workstations. They establish the basis for the minimum and maximum number of personnel to be accommodated and requirements for coordinating activities between personnel.

Evaluation of Criterion (1)

In RAI 18.8-41, the staff requested that the applicant clarify ambiguous design inputs in the HSI design process block diagram in NEDO-33268, Figure 2, Revision 0. RAI 18.8-41 was being tracked as an open item in the SER with open items. Through multiple supplemental responses, the applicant clarified that it added information to address this criterion through other RAIs, including an alternative Figure 2, and that the block diagram was no longer necessary and therefore was deleted. The staff finds that the response is acceptable since sufficient information to address the criterion is available, as described below, without the block diagram. The staff verified that the applicant implemented the proposed changes in NEDO-33268, Revision 3. Based on the applicant's responses and changes to NEDO-33268, RAI 18.8-41 is resolved.

NEDO-33268, Revision 5, Sections 3.1.4 and 4.1.2, discuss the input of task analysis results to the HSI design. NEDO-33268, Revision 5, Figures 1 and 2, provide a graphic overview of the HSI design process that details the inputs to the process. Key inputs to the process are the results of the OER, operations analysis (including FRA, FA, and task analysis), and staffing analyses.

Regarding OER, Section 3.2.1, "Background," item 1a, specifically states that the ABWRs are included in the OER input for the ESBWR CR design. In addition, the plan commits to reviewing other plant designs with similar HSIs not limited to nuclear plants. Aspects of HSI addressed include use of flat screen displays, soft controls, and alarm prioritization. Lessons learned are incorporated into the OER/BRR for use by system designers.

FRA and FA define the level of automation and the human role, which is further analyzed in task analysis to identify specific displays, data processing, controls, and job support aids needed to accomplish tasks. The HSI design supports these requirements. Section 4.1.2 lists these elements, along with associated attributes identifying decision making, response, and task support needs. Staffing analyses provide input, as well, by identifying tasks performed by individual crew members.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for personnel task requirements development acceptable.

- (2) System Requirements—Constraints imposed by the overall instrumentation and control (I&C) system should be considered throughout the HSI design process.

Evaluation of Criterion (2)

In accordance with NEDE-33217P, Revision 6, the design process integrates the design of I&C and HFE. This integration provides adequate assurance that the HSI design reflects the constraints imposed by the I&C system. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for I&C system constraints acceptable.

- (3) Regulatory Requirements—Applicable regulatory requirements should be identified as inputs to the HSI design process.

Evaluation of Criterion (3)

The applicant has identified applicable NRC requirements and guidance as input to its process, including 10 CFR Part 50, NUREG-0711, and NUREG-0700. NUREG-0696 provides guidance for HSIs for the emergency response facilities. These documents are identified in Section 2.3 and as inputs in various sections of the plan. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for regulatory requirement input acceptable.

- (4) Other Requirements—The applicant should identify other requirements that are inputs to the HSI design.

Evaluation of Criterion (4)

In NEDO-33268, Revision 5, the applicant identified additional inputs to the HSI design, including the HRA/PRA and diversity and defense-in-depth (D3) analyses. These are appropriate sources of requirements for HSI design. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for other requirements acceptable.

18.8.3.1.2 Concept of Operations

- (1) A concept of operations should be developed indicating crew composition and the roles and responsibilities of individual crew members based on anticipated staffing levels. The concept of operations should:
 - Identify the relationship between personnel and plant automation by specifying the responsibilities of the crew for monitoring, interacting [with], and overriding automatic systems and for interacting with computerized procedures systems and other computerized operator support systems.
 - Provide a high-level description of how personnel will work with HSI resources. Examples of the types of information that should be identified [are] the allocation of tasks to the main control room or local control stations, whether personnel will work at a single large workstation or individual workstations, what types of information each crew member will have access to, and what types of information should be displayed to the entire crew.
 - Address the coordination of crew member activities, such as the interaction with auxiliary operators, and coordination of maintenance and operations.

Evaluation of Criterion (1)

The "Concept of Operation" describes the operator's interface with the HSI design. NEDO-33268, Revision 5 in Sections 3.1.3 and 3.3.5.4 describes the methodology used to develop the concept of operations. In Section 3.1.3, the applicant addresses personnel functions and tasks, staffing and qualifications, and the working environment, including various types of HSIs. Section 3.3.5.4 provides additional detail on the treatment of staffing and qualifications. Staffing composition and roles and responsibilities of individual staff members will be identified. In addition, the concept of operations will address the relationship of plant staff with automation, including its role of monitoring, interacting with, and backing up automated systems. The analysis will include not only process automation, but also automation that will be used in support systems such as computerized procedures.

In RAI 18.8-50, the staff requested that the applicant provide details on how the concept of operations will be developed and documented. As documented through several supplemental RAIs, the staff determined that the necessary level of detail was in the applicant's internal work instructions and needed to be incorporated into the IP, NEDE-33268P. RAI 18.8-50 was being tracked as an open item in the SER with open items. In response to this RAI, the applicant provided the information at a level of detail sufficient for the staff to complete their review of the criterion for concept of operations development and incorporated this information into NEDE-33268P, Revision 4, Appendix A. The staff evaluation of the IP, as updated through the RAI response, is described below. Based on the applicant's responses and the NEDE-33268P revisions, RAI 18.8-50 is resolved.

NEDE-33268P, Revision 5, Appendix A, provides additional proprietary detail on the steps used by the design team to implement the plan. Eight steps are described to develop the concept of operations. The proprietary SER outlines these steps to demonstrate how the method conforms to the NUREG criterion. A concept of operations document will be prepared to document the results of the effort. This methodology will provide a suitable concept of operations in support of detailed HSI design.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for concept of operations development acceptable.

18.8.3.1.3 Functional Requirement Specification

(1) Functional requirements for the HSIs should be developed to address:

- The concept of operations
- Personnel functions and tasks that support their role in the plant as derived from function, task, and staffing/qualifications analyses
- Personnel requirements for a safe, comfortable working environment

Evaluation of Criterion (1)

NEDO-33268, Revision 5, Section 3.1.3, and NEDE-33268P, Revision 5, Appendix A, discuss functional requirements for the HSIs. The concept of operations is developed as described above. The results define HFE design attributes. The design attributes are collected into functional requirements that become design input for the HFE design process.

NEDO-33268, Revision 5, Figure 2, graphically illustrates the relationship between functional requirements and other HSI design activities. Inputs to functional requirements development are shown as OER/BRR, FRA, FA, task analysis and staffing and qualifications analyses. Section 4.1.2 provides additional information in terms of the contributions of these analyses to functional requirement development. Personnel functions and tasks are addressed in each of these 4 elements of the HFE design process. In each element HFE design attributes are identified and collected into functional requirements that become design input to the HFE design process.

NEDE-33268P, Revision 5, Appendix A provides additional information on functional requirements development. The requirements identified are entered into the requirements tracking software where they are assessed for conformity with NUREG-0700 and incorporated into the style guide. Implementation of HSI guidelines contained in NUREG-0700 provides for

an effective interface between the equipment and operators, as well as a safe and comfortable work environment.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for the establishment of functional requirements acceptable.

- (2) Requirements should be established for various types of HSIs, e.g., alarms, displays, and controls.

Evaluation of Criterion (2)

In RAI 18.8-51, the staff requested that the applicant provide details on how the HFE team would develop and document the functional requirements for the HSI. As documented through several supplemental RAIs, the staff determined that the necessary level of detail was in the applicant's internal work instructions and needed to be incorporated into the IP, NEDE-33268P. RAI 18.8-51 was being tracked as an open item in the SER with open items. In response to this RAI, the applicant provided the information at a level of detail sufficient for the staff to complete its review of the criterion for concept of operations development and incorporated this information into NEDE-33268P, Revision 4. The staff evaluation of the IP, as updated through the RAI response, is described below. Based on the applicant's responses and the NEDE-33268P revisions, RAI 18.8-51 is resolved.

NEDO-33268, Revision 5, Section 3.1.3, indicates that HSI functional requirements address CDAs. As noted in the evaluation of Criterion (1) above, HSI requirements are tracked using a requirements tracking software and ultimately incorporated into the ESBWR style guide which provides a description of all HSI resources, including CDAs. NEDO-33268, Revision 5, Section 4.3.4.10, "Display Systems," provides examples of functional requirements for the display system.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for identifying CDA specifications acceptable.

18.8.3.1.4 Human-System Interface Concept Design

The development of an HSI concept design, which is mainly discussed in NEDO-33268, Revision 5, Sections 3.1 and 4.1, is one of three key elements of the HSI Design Plan (along with style guide development and detailed HSI design).

- (1) The functional requirement specification should serve as the initial source of input to the HSI design effort. If the design is a direct evolution from a predecessor, rather than a new design concept, the criteria in this section should be considered relative to operating experience of the predecessor and the design features (e.g., aspects of the process, equipment, or operations) of the new design that may be different from the predecessor. Human performance issues identified from operating experience with the predecessor design should be resolved.

Evaluation of Criterion (1)

The ESBWR concept design is an evolution from a predecessor design, the ABWR (as discussed above). The applicant identified the functional requirements specification as an input to the design process, along with the other inputs discussed above in Section 18.8.3.1.3 of this

report. Human performance of the predecessor is captured in the OER, documented in the OER/BRR, and made available to the design team. NEDO-33268, Revision 5, Section 4.1.2, discusses how the OER is assessed to provide input to the HSI design process. In NEDE-33268P, Revision 5, the applicant provided specific procedures describing how OER information is used. The HSI implications identified through the analysis of HSI-related OER items is entered into the requirements tracking software, where it is assessed for conformance with NUREG-0700 and incorporated into the style guide. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for concept design acceptable.

(2) Alternative approaches for addressing HSI functional requirements should be considered. A survey of the state-of-the-art in HSI technologies should be conducted to:

- Support the development of concept designs that incorporate advanced HSI technologies
- Provide assurance that proposed designs are technically feasible
- Support the identification of human performance concerns and tradeoffs associated with various HSI technologies

Evaluation of Criterion (2)

NEDO-33268, Revision 4, Section 3.1, states that performing an assessment of state-of-the-art HSI technologies is part of the design process. In the July 2007 regulatory audit, the applicant summarized its comprehensive technology assessment, which included evaluations of complex systems beyond current nuclear plant applications. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for a survey of the state of the art acceptable.

(3) Alternative approaches for addressing HSI functional requirements should be considered. Evaluation methods can include operating experience and literature analyses, tradeoff studies, engineering evaluations and experiments.

Evaluation of Criterion (3)

The applicant is using a variety of approaches, including the use of operating experience and simulation assessments to enhance the design. In the July 2007 regulatory audit, the applicant provided a review of its assessment of alternative approaches and explained how its analyses are being used to select methods for incorporation into the ESBWR design. These regulatory audit results indicated that the applicant was seriously evaluating alternative approaches in a systematic manner. In NEDO-33268, Revision 5, Section 3.1, the applicant states that it will evaluate alternative concept designs using tradeoff evaluations (evaluations that compare the positive and negative attributes of one design solution against another and identify the better solution). Section 3.3.5.6 provides additional information as to how these evaluations will be accomplished. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for alternative approaches acceptable.

(4) Alternative concept designs should be evaluated so that one can be selected for further development. The evaluation should provide reasonable assurance that the selection process is based on a thorough review of design characteristics and a systematic application of selection criteria. Tradeoff analyses, based on the selection criteria, should provide a rational basis for the selection of concept designs.

Evaluation of Criterion (4)

In accordance with NEDE-33268P, Revision 5, Section 3.1, "Concept Design," the ESBWR HSI design reflects the evolution of the ABWR HSIs by taking advantage of ABWR operating experience, as well as that of other complex systems. As an evolutionary design, a list of standard features has been identified to serve as an overall framework for developing the design. The standard features are those ABWR resources, such as the large overview display and workstation arrangement, that are the starting place for the design. Any issues identified in operating experience, for example, are resolved in the design process. Thus, the applicant is evaluating alternative designs at the level of HSI design details. These evaluations are performed using information from operating experience, literature evaluations, tradeoff studies, and engineering evaluations. Figures in NEDE-33268P, Revision 5, Appendix B, provide forms and measures for performing these analyses. The staff considers this an appropriate approach for an evolutionary design that is based on a proven HSI design with successful operating experience. Such an approach provides selected improvements to the design rather than a complete redesign. Accordingly, the staff finds the HSI Design Plan's treatment of Criterion (4) for evaluating alternative approaches acceptable.

- (5) HSI design performance requirements should be identified for components of the selected HSI concept design. These requirements should be based on the functional requirement specifications but should be refined to reflect HSI technology considerations identified in the survey of the state of the art in HSI technologies and human performance considerations identified in the human performance research.

Evaluation of Criterion (5)

NEDE-33268P, Revision 5, Section 3.1, indicates that HSI performance requirements are based on functional requirements that are refined to reflect HSI considerations identified in a survey that the applicant conducted of state-of-the-art HSI technology. HSI performance requirements are also considered as one of the factors in the HSI tradeoff evaluations. NEDE-33268P, Revision 5, Figure B-2, lists proprietary examples of the factors used. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for design performance requirements acceptable.

18.8.3.1.5 Human System Interface Detailed Design and Integration

During its review of NEDO-33268, Revision 0, the staff determined that it needed additional detail to evaluate Criterion (1) and Criteria (3) through (9). The staff initiated RAIs for each criterion. While the applicant committed to meet each of the objectives in Criterion (1) and Criteria (3) through (9), the applicant provided no guidance on how the objectives would be met. In RAIs 18.8-2 and 18.8-52 through 18.8-58, the staff requested that the applicant provide (1) step-by-step direction on how to perform the HSI design in the HSI Design Plan (Criterion (1), RAI 18.8-2), (2) details on the design and methodology used for minimizing error associated with risk-important actions (Criterion (3), RAI 18.8-52), (3) details on the design and methodology for developing monitoring and control measurements (Criterion (4), RAI 18.8-53), (4) details on the design of the HSI layout (Criterion (5), RAI 18.8-54), (5) guidance on accommodating varying staffing levels in the CR (Criterion (6), RAI 18.8-55), (6) details on the impact on HSIs of fatigue over a shift (Criterion (7), RAI 18.8-56), (7) details on the use of HSIs under a full range of environmental conditions (Criterion (8), RAI 18.8-57), and (8) details on HSI support for test, inspection, and maintenance (Criterion (9), RAI 18.8-58).

For each of these RAIs, as documented through several supplemental RAIs, the staff determined that the necessary level of detail was in the applicant's internal work instructions and needed to be incorporated into the IP, NEDE-33268P. RAIs 18.8-2 and 18.8-52 through 18.8-58 were being tracked as open items in the SER with open items. In response to these RAIs, the applicant provided the information at a level of detail sufficient for the staff to complete its review of the criteria for HSI detailed design and integration and incorporated this information into NEDE-33268P, Revision 5, Appendix A. The applicant also clarified where the methodology to address HSI design is made available, clarified issues regarding the implementation and use of the HSI style guide, and corrected references to tables, figures, and the appendix in its response to RAI 18.8-2. The staff evaluation of the IP, as updated through the RAI responses, is described below. Based on the applicant's responses and the NEDE-33268P revisions, RAIs 18.8-2 and 18.8-52 through 18.8-58 are resolved.

- (1) Design-specific HFE design guidance (style guide) should be developed. HFE Guidelines should be utilized in the design of the HSI features, layout, and environment.
 - The content of the Style Guide should be derived from (1) the application of generic HFE guidance to the specific application, and (2) the development of the applicant's own guidelines based upon design-related analyses and experience. Guidelines that are not derived from generic HFE guidelines may be justified by the applicant based on an analysis of recent literature, analysis of current industry practices and operational experience, tradeoff studies and analyses, and the results of design engineering experiments and evaluations. The guidance should be tailored to reflect design decisions by the applicant to address specific goals and needs of the HSI design.
 - The topics in the Style Guide should address the scope of HSIs included in the design and address the form, function, and operation of the HSIs as well as environmental characteristics relevant to human performance.
 - The individual guidelines should be expressed in concrete, easily observable terms. In general, generic HFE guidelines should not be used in their abstract form. Such generic guidance should be translated into more specific design guidelines that can, as much as possible, provide unambiguous guidance to designers and evaluators. They should be detailed enough to permit their use by design personnel to achieve a consistent and verifiable design that meets the applicant's guideline.
 - The Style Guide should provide procedures for determining where and how HFE guidance is to be used in the overall design process. The Style Guide should be written so it can be readily understood by designers. The Style Guide should support the interpretation and comprehension of design guidance by supplementing text with graphical examples, figures, and tables.
 - The guidance should be maintained in a form that is readily accessible and usable by designers and that facilitates modification when the contents require updating as the design matures. Each guideline included in the guidance documentation should include a reference to the source upon which it is based.
 - The Style Guide should address HSI modifications. This guidance should specifically address consistency in design across the HSIs.

Evaluation of Criterion (1)

NEDO-33268, Revision 5, Sections 3.2 and 4.2, discuss the development and application of the ESBWR style guide. The style guide addresses the topics outlined throughout the HSI plan which include HSI resources such as CDAs, and SPDS. The materials to be used as an input to the style guide include the operating experience of the ABWR, HFE guidance documents (such as NUREG-0700), appropriate RGs, and the results of the applicant's evaluation of design tradeoffs. Provisions for modification of the contents of the style guide are identified. In addition, NEDO-33268, Revision 5, Appendix A, provides sample pages from the draft style guide to illustrate the results of the process used and the level of detail provided in the guidance. The guidance is expressed in concrete unambiguous terms. This will permit the guide to be used consistently by design engineers.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for style guide development acceptable.

- (2) The HSI detailed design should support personnel in their primary role of monitoring and controlling the plant while minimizing personnel demands associated with use of the HSIs (e.g., window manipulation, display selection, display system navigation). NUREG-0700 describes high-level HSI design review principles that the detailed design should reflect.

Evaluation of Criterion (2)

NEDO-33268, Revision 5, Section 3.3.5.2, discusses the general approach the applicant took to addressing the primary role of plant personnel in terms of monitoring/detection, situation awareness, interpretation and planning, control, and feedback. NEDO-33268, Revision 5, Section 3.2, specifies that the ESBWR style guide contain detailed guidance for supporting these roles in terms of the HFE design of individual HSI systems. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for personnel support acceptable.

- (3) For risk-important HAs, the design should seek to minimize the probability that errors will occur and maximize the probability that an error will be detected if one should be made.

Evaluation of Criterion (3)

NEDO-33268, Revision 5, Section 3.3.4 indicates that the design seeks to minimize the probability of errors involving risk-important actions and maximize the probability of error detection. NEDO-33268P, Revision 5, Appendix A, provides proprietary work process steps to accomplish this objective. In general, many different factors that affect the operator's ability to perform each HA are evaluated. The proprietary SER provides a summary of these work steps to illustrate how the process conforms to the NUREG criterion.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for addressing risk-important actions acceptable.

- (4) When developing functional requirements for monitoring and control capabilities that may be provided either in the control room or locally in the plant, the following factors should be considered:
 - Communication, coordination, and workload
 - Feedback
 - Local environment

- Inspection, test, and maintenance
- Importance to safety

Evaluation of Criterion (4)

NEDO-33268, Revision 5, Section 3.3.4, indicates that, in developing HSI monitoring and control measures, the following considerations are addressed: (1) communication, coordination, and workload; (2) feedback; (3) local environment; (4) inspection, test, and maintenance; and (5) risk-importance. In NEDE-33268P, Revision 5, Appendix A, the applicant provides additional proprietary information addressing each of the considerations. The proprietary SER summarizes the process used for each consideration so that there is a clear demonstration of how each consideration is managed. By describing what considerations are addressed as well as how they are managed, the applicant provides a complete explanation of how its HSI design process conforms to this criterion.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for monitoring and control capabilities acceptable.

- (5) The layout of HSIs within consoles, panels, and workstations should be based upon (1) analyses of operator roles (job analysis) and (2) systematic strategies for organization such as arrangement by importance, frequency of use, and sequence of use.

Evaluation of Criterion (5)

NEDO-33268, Revision 5, Section 3.3.4 indicates that the layout of HSIs is based on a job analysis; strategies for organization, such as by importance; and accommodation of D3 (diversity and defense in depth) design considerations. NEDE-33268P, Revision 5, Appendix A, provides proprietary work process steps to accomplish these objectives. The proprietary SER identifies the specific steps that demonstrate conformance to this criterion.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for HSI layout acceptable.

- (6) Personnel and task performance should be supported during minimal, nominal, and high-level staffing.

Evaluation of Criterion (6)

NEDO-33268, Revision 5, Section 3.3.4 indicates that the HSI design will support personnel and task performance during different staffing levels. NEDE-33268P, Revision 5, Appendix A, provides proprietary work process steps to accomplish this objective. The proprietary SER identifies the specific steps that demonstrate conformance to this criterion. The approach addresses the HSI design's accommodation of varying staffing levels.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for accommodation of varying staffing levels acceptable.

- (7) The design process should take into account the use of the HSIs over the duration of a shift where decrements in performance due to fatigue may be a concern.

Evaluation of Criterion (7)

NEDO-33268, Revision 5, Section 3.3.4, indicates that the HSI design process will address the use of HSIs across a shift. NEDE-33268P, Revision 5, Appendix A, provides proprietary work process steps to accomplish this objective. The proprietary SER identifies the specific steps that demonstrate conformance to this criterion. The approach addresses the HSI design's accommodation of shift duration.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for accommodation of shift duration acceptable.

- (8) HSI characteristics should support human performance under the full range of environmental conditions, e.g., normal as well as credible extreme conditions. For the main control room requirements should address conditions such as loss of lighting, loss of ventilation, and main control room evacuation. For the remote shutdown facility and local control stations, requirements should address constraints imposed by the ambient environment (e.g., noise, temperature, contamination) and by protective clothing (if necessary).

Evaluation of Criterion (8)

NEDO-33268, Revision 5, Section 3.3.4, indicates that the HSI will support human performance under a range of environmental conditions. NEDE-33268P, Revision 5, Appendix A, provides proprietary work process steps to accomplish this objective. The proprietary SER identifies the specific steps that demonstrate conformance to this criterion. The approach addresses the HSI design's support for human performance under a range of environmental conditions.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for accommodation of environmental conditions acceptable.

- (9) The HSIs should be designed to support inspection, maintenance, test, and repair of (1) plant equipment and (2) the HSIs. The HSIs should be designed so that inspection, maintenance, test, and repair of the HSIs do not interfere with other plant control activities (e.g., maintenance tags should not block the operators' views of plant indications).

Evaluation of Criterion (9)

NEDO-33268, Revision 5, Section 3.3.4, indicates that the HSI will be designed to support test, inspection, and maintenance activities. NEDE-33268P, Revision 5, Appendix A, provides proprietary work process steps to accomplish this objective. The proprietary SER identifies the specific steps that demonstrate conformance to this criterion. The approach addresses the HSI design's support for test, inspection, and maintenance activities.

Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for accommodation of test, inspection and maintenance activities acceptable.

18.8.3.1.6 Human System Interface Tests and Evaluations

There were three RAI open items associated with multiple criteria in this section. All eleven criteria for the HSI tests and evaluations review topic (including the two criteria for trade-off evaluations and the nine criteria for performance based tests) had open items identified in the

SER with open items. The applicant has satisfactorily addressed all of these open items as described below. With the resolution of the RAIs, which in some cases resulted in significant changes to the IP, the applicant now has an IP that can be evaluated systematically against the NUREG-0711 criteria. Accordingly, only a brief summary of the previously open RAIs is presented to preserve the flow of the remainder of the evaluation against the individual NUREG-0711 criteria.

In RAI 18.8-33, the staff requested the that applicant clarify the HFE activities and ratings listed in NEDO-33268, Revision 2, Figure 5, "Appropriate Data Collection Methods for HFE Activities." RAI 18.8-33 was being tracked as an open item in the SER with open items. In its RAI response, the applicant indicated that it would remove the figure from NEDO-33268. The staff finds that the applicant's response is acceptable since the figure is not necessary to address the HSI test and evaluation criteria. The staff confirmed that the applicant removed the figure from NEDO-33268, Revision 3. Based on the applicant's response and NEDO-33268 revision, RAI 18.8-33 is resolved.

In RAIs 18.8-35 and 18.8-59, the staff requested that the applicant provide details on (1) the methods used for HSI tests and evaluations (RAI 18.8-35) and (2) tradeoff evaluations. As documented in each of these RAIs and several supplemental RAIs, the staff determined that the necessary level of detail was in the applicant's internal work instructions and needed to be incorporated into the IP, NEDE-33268P. RAIs 18.8-35 and 18.8-59 were being tracked as open items in the SER with open items. In response to these RAIs, the applicant provided the information at a level of detail sufficient for the staff to complete its review of the criteria for HSI tests and evaluations and incorporated this information into NEDE-33268P, Appendix B, Revision 5. The staff evaluation of the IP, as updated through the RAI responses, is described below. Based on the applicant's responses and the NEDE-33268P revisions, RAIs 18.8-35 and 18.8-59 are resolved.

18.8.3.1.6.1 Trade-Off Evaluations

- (1) Aspects of human performance that are important to task performance should be carefully selected and defined so that the differential effects of design options on human performance can be adequately considered in the selection of design approaches. The following factors should be considered when developing selection criteria:
 - Personnel task requirements
 - Human performance capabilities and limitations
 - HSI system performance requirements
 - Inspection and testing requirements
 - Maintenance requirements
 - Use of proven technology and the operating experience of predecessor designs.

Evaluation of Criterion (1)

NEDO-33268, Revision 5, Section 3.3.5.6, and NEDE-33268P, Revision 5, Appendix B, describe the use of tradeoff evaluations. These sections provide a proprietary list of key criteria to compare in trade-off evaluations. The proprietary SER describes how this list is used and provides examples of key selection criteria that include those in this criterion as well as others the applicant has added. This approach acceptably addresses the identification of selection criteria for tradeoff evaluations. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for tradeoff evaluation criteria acceptable.

- (2) The selection process should make explicit the relative benefits of design alternatives and the basis for their selection.

Evaluation of Criterion (2)

NEDO-33268, Revision 5, Section 3.3.5.6, and NEDE-33268P, Revision 5, Appendix B, describe the use of tradeoff evaluations. These sections indicate that the HFE team uses tradeoff evaluations to determine the relative benefits of selected design alternatives. NEDE-33268P, Revision 5, Appendix B, provides a proprietary explanation of the selection process. In general the methods being used are quantitative. The proprietary SER summarizes the explanation to demonstrate conformance to the NUREG criterion. The approach acceptably identified the explicit benefits of each design alternative and the basis for the alternative selected. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for benefits of design alternatives and basis for selection acceptable.

18.8.3.1.6.2 Performance-Based Tests

- (1) Performance-based tests can have many different purposes; therefore, the hypotheses should be structured to address the specific questions being addressed.

Evaluation of Criterion (1)

NEDO-33268, Revision 5, Section 3.3.5.6, describes performance-based tests. This section recognizes that performance tests must be specifically defined so the test satisfies the objective. Appendix B, Section B.3(3) of the same document directs that an "appropriate hypothesis for testing" be identified. A proprietary testing process is specifically defined in Appendix B, Section B.1, "Evaluation of Goal Establishment." In general the process requires specific information on the proposed test and its purpose. The proprietary SER summarizes how this testing process is initiated which illustrates how conformance to this criterion is obtained. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for hypothesis structuring acceptable.

- (2) The general approach to testing should be based on the test objective. The design of performance-based tests should be driven by the purpose of the evaluation and the maturity of the design.

Evaluation of Criterion (2)

NEDO-33268, Revision 5, Section 3.3.5.6, describes performance-based tests. This section indicates that the tests performed will depend on the specific purpose of the evaluation, the questions being addressed, and the maturity of the design. Appendix B, Section B.1 describes how test objectives are developed as part of "Evaluation Goal Establishment." The evaluation of Criterion (1) above describes how this is done. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for test objective development acceptable.

- (3) The specific design features or characteristics of design features should be carefully defined. If the characteristics are to be manipulated in the test, i.e., systematically varied, the differences between test conditions should be specified in detail.

Evaluation of Criterion (3)

NEDO-33268, Revision 5, Section 3.3.5.6, and NEDE-33268P, Revision 5, Appendix B, describe performance-based tests. Design feature definition is identified in the test and evaluation direction found in NEDE-33268P, Revision 5, Appendix B, Section B.1, paragraph 1 and Figure B-1. Appendix B further identifies that specific design features or characteristics to be evaluated in a test are defined as part of the goal definition for the test. This includes a description of how features are systematically varied as part of the test. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for feature definition acceptable.

- (4) The selection of testbeds for the conduct of performance-based tests should be based upon the requirements imposed by the test hypotheses and the maturity of the design.

Evaluation of Criterion (4)

NEDO-33268, Appendix B, Section 3.3.5.6, and NEDE-33268P, Revision 5, Appendix B, describe performance-based tests. These sections indicate that testbed selection is based on testing objectives and design maturity. A variety of testbeds are discussed, including mockups and part-task simulators. Full-scope simulators will be used for integrated system validation. The plan states that dynamic simulators are used when the detailed design analysis relies upon critical human performance. NEDE-33268P, Revision 5, Appendix B, Section B.3, paragraph 4, identifies proprietary procedures for testbed selection. Generally the criteria are specific and address those areas identified in the criterion. The proprietary SER provides examples of specific criteria use for testbed selection in order to demonstrate conformance with the NUREG criterion. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for testbed selection acceptable.

- (5) The selection of performance measures should be based on a consideration of:
- Measurement characteristics
 - Identification and selection of variables to represent measures of the aspects of performance under investigation
 - Development of performance criteria.

Evaluation of Criterion (5)

NEDO-33268, Revision 5, Section 3.3.5.6, describes performance-based tests. This section indicates that performance measures are selected based on measurement characteristics, identification and selection of variables, and performance criteria. A variety of performance measurement categories are identified, including system measures, personnel primary task measures, secondary tasks, errors, situation awareness, workload, and communications. NEDE-33268P, Revision 5, Appendix B, provides additional detail on how tests and evaluations are performed. Figure B-4 provides additional proprietary information on some of the specific measures to be used and their acceptance criteria. The proprietary SER provides an example of a measure and its acceptance criteria to demonstrate conformance with the NUREG criterion.

The applicant has provided a reasonable basis for the performance measures it is using. The specificity of the performance measures provides reasonable assurance that specific, meaningful conclusions can be reached on the testing objectives. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for performance measurement acceptable.

- (6) The selection of participants for HSI design tests should be based on the nature of the questions being addressed in test objectives and the level of design maturity.

Evaluation of Criterion (6)

NEDO-33268, Revision 5, Section 3.3.5.6, and NEDE-33268P, Revision 5, Appendix B, describe performance-based tests. These sections indicate that the selection of participants depends on the purpose of the evaluation and design maturity. NEDE-33268P, Revision 5, Appendix B, Section B.3, paragraphs 8 and 9, provide proprietary details on how participant selection is accomplished. The proprietary SER identifies the specific detail that demonstrates the selection process conforms to this NUREG criterion. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for participant selection acceptable.

- (7) The test design should permit the observation of performance in a manner that avoids or minimizes bias, confounds, and error variance (noise).

Evaluation of Criterion (7)

NEDO-33268, Revision 5, Section 3.3.5.6, and NEDE-33268P, Revision 5, Appendix B, describe performance-based tests. These sections indicate that the test design will minimize bias, confounds, and error variance. NEDE-33268P, Revision 5, Appendix B, Section B.3, paragraph 10, addresses minimizing bias, confounds, and error variance. Specific proprietary techniques are described to explain how this is accomplished. The proprietary SER summarizes this material to illustrate how conformance to the NUREG criterion is accomplished. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for minimizing bias, confounds, and error variance acceptable.

- (8) Test data should be analyzed using established analysis techniques.

Evaluation of Criterion (8)

NEDE-33268P, Revision 5, Appendix B, Section B3, paragraph 5, describes proprietary approaches to data analysis. The proprietary SER summarizes this material to illustrate how conformance to the NUREG criterion is accomplished. The tests identified are acceptable in the applications in which they are being used. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for data analysis acceptable.

- (9) Design solutions, such as modifications of the HSIs or user training requirements, should be developed to address problems that are identified during the testing and evaluation of the HSI detailed design.

Evaluation of Criterion (9)

NEDO-33268, Revision 5, Section 3.3.5.6, and NEDE-33268P, Revision 5, Appendix B, describe performance-based tests. These sections indicate that design solutions are developed to address problems that are identified during the testing and evaluation of the HSI design. NEDE-33268P, Revision 5, Appendix B, Section B3, paragraph 13, indicates that test reports should identify recommendations for potential design resolutions (e.g., modifications to HSIs) or training. The design procedures described in NEDE-33268P, Revision 5, Appendix A, are used to address the analysis of potential solutions. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for development of design solutions acceptable.

18.8.3.1.7 Human System Interface Design Documentation

(1) The HSI design should be documented to include:

- The detailed HSI description including its form, function and performance characteristics
- The basis for the HSI requirements and design characteristics with respect to operating experience and literature analyses, tradeoff studies, engineering evaluations and experiments, and benchmark evaluations
- Records of the basis of the design changes.

Evaluation of Criterion (1)

NEDO-33268, Revision 5, Section 5.1, identifies the contents of the results summary report. The plan specifies that the summary report is written in sufficient detail to document how the HSI design methodology presented in the plan was implemented to provide the results. Included in its contents are the approach to HSI design, the style guide and design bases, the methods used for test and evaluation, and the process for refining and updating the HSI design.

The HSI Design Plan provides for documenting the HSI design, including the detailed HSI design description, the basis for the HSI requirements and design characteristics, and records of the basis for design changes as described in detail above. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for HSI design documentation acceptable.

(2) The outcomes of tests and evaluations performed in support of HSI design should be documented.

Evaluation of Criterion (2)

As noted in the evaluation under Criterion (1) above, the applicant's HSI design plan specifies that a results summary report is prepared to document the methodology presented in the plan. This includes activities described in NEDO-33268, Revision 5, Section 3.3.5.6, "Tests and Evaluations." The HSI Design Plan also includes documenting the outcomes of tests and evaluations performed in support of HSI design. Accordingly, the staff finds the HSI Design Plan's treatment of the criterion for documentation of outcomes acceptable.

18.8.3.2 Safety Parameter Display System Design

The staff focused its review on an evaluation of the information provided by the applicant pertaining to the SPDS with respect to the requirements of 10 CFR 50.34(f)(2)(iv), which apply to design certification applications by virtue of 10 CFR 52.47(a)(8), and the criteria contained in NUREG-0711 and NUREG-0700, Section 5. The NRC previously used NUREG-0737, "Clarification of TMI Action Plan Requirements," Supplement 1, and NUREG-1342, "A Status Report Regarding Industry Implementation of Safety Parameter Display System," issued April 1989, for review guidance, but this guidance has been subsumed into Section 5 of NUREG-0700. NUREG-0711, Section 8.4.5, "HSI Detailed Design and Integration," which is evaluated above, also refers to NUREG-0700. This review considered the extent to which the applicant's design processes support the functions required for the SPDS because the applicant has not completed the detailed design of the CR displays. Accordingly, an evaluation of conformance to the requirements of 10 CFR 50.34(f)(2)(iv) and the guidelines of NUREG-0700, Section 5, follow.

(1) 10 CFR 50.34(f)(2)(iv): General SPDS Requirements

Title 10, Subsection 50.34(f)(2)(iv) of the *Code of Federal Regulations* requires that the design provide a plant safety parameter display console that will (1) display to operators a minimum set of parameters defining the safety status of the plant, (2) be capable of displaying a full range of important plant parameters and data trends on demand, and (3) be capable of indicating when process limits are being approached or exceeded.

Evaluation of Criterion (1)

The applicant has requested an exemption from the requirements of 10 CFR 50.34(f)(2)(iv). The applicant addresses the criteria in 10 CFR 50.12 by proposing an alternative means of meeting the underlying purpose of 10 CFR 50.34(f)(2)(iv). As described in NEDO-33268, Revision 5, Section 4.3.4.18, "SPDS," the applicant addressed the SPDS concerns and criteria with an integrated design, rather than a stand-alone, add-on system as is used at most currently operating plants. The ESBWR design will address the regulatory requirements by integrating features to comply with the SPDS requirements into the design of the alarm and display systems. In the SRP, the staff indicated that for applicants who are in the early stages of the CR design, the "function of a separate SPDS may be integrated into the overall control room design."

The staff has determined that the special circumstances described in 10 CFR 50.12(a)(2)(ii) exist in that application of 10 CFR 50.34(f)(2)(iv) would serve the underlying purpose of that rule in the context of ESBWR design. The applicant has provided an acceptable alternative that accomplishes the purpose of the regulation. The requirement for an SPDS console need not be applied in this particular circumstance to achieve the underlying purpose for an SPDS, which is to provide a CR improvement that enhances operator ability to comprehend plant conditions and interact in situations that call for human intervention. The SPDS should provide a concise display of critical plant variables to CR operators to aid them in rapidly and reliably determining the safety status of the plant. For the ESBWR, this purpose is accomplished by the plant alarm and display systems.

On this basis, the staff concludes that special circumstances are present for the proposed exemption from the requirements of 10 CFR 50.34(f)(2)(iv) for an SPDS console. In addition, the proposed exemption is authorized by law, will not present an undue risk to public health and safety, and is consistent with the common defense and security. NUREG-0700 addresses other design guidelines which are evaluated below.

(2) NUREG-0700 Section 5: Specific SPDS guidelines state:

The primary function of these monitoring systems, which operate during all plant conditions, is to present information to aid control room personnel during abnormal and emergency conditions in determining the safety status of the plant and in assessing whether conditions warrant corrective actions by operators to avoid a degraded core. This function is particularly important during anticipated transients and in the initial phase of an accident.

Evaluation of Criterion (2)

In RAI 18-8.44, the staff requested that the applicant address the guidelines of NUREG-0700, Revision 2, Section 5, since NEDO-33268, Revision 0, only committed to follow the guidelines in

the older document, NUREG–0737, Supplement 1. In response, the applicant stated that it would revise NEDO-33268 to state that the SPDS design is implemented in accordance with NUREG–1342 and NUREG–0700, Revision 2, Section 5, in addition to NUREG–0737, Supplement 1. The staff finds that the applicant's response is acceptable since the applicant committed to a comprehensive set of guidance for the SPDS design. Based on the applicant's response, RAI 18.8-44 is resolved. RAI 18-8.44 was being tracked as a confirmatory item in the SER with open items. The staff verified that the applicant implemented the proposed changes in NEDO-33268, Revision 3. Based on the NEDO-33268 revision, the confirmatory item is closed.

In RAI 18.8-45, the staff requested that the applicant clarify the optional display of SPDS variables in the TSC and EOF as described in NEDO-33268, Section 4.3.4.18, Revision 0. The staff had determined that this approach was inconsistent with NUREG–0696 because the SPDS variables should be available in the TSC and EOF. In response, the applicant clarified that the SPDS variables that are displayed in the CR will be available in the TSC and EOF. Based on the applicant's response, RAI 18.8-45 is resolved. RAI 18.45 was being tracked as a confirmatory item in the SER with open items. The staff verified that the applicant implemented the proposed changes in NEDO-33268, Revision 3. Based on the NEDO-33268 revision, the confirmatory item is closed.

NEDO-33268, Revision 5, Sections 3.3.5.18 and 4.3.4.18, discuss the SPDS for the ESBWR. The SPDS will display critical plant variables on the wide display panel for the following critical safety functions:

- Reactivity control
- Reactor core cooling and heat removal from the primary system
- Reactor coolant system integrity
- Radioactivity control
- Containment conditions

These variables are continuously displayed on the large screen display as an integral part of the fixed-position displays. The plan indicates that the SPDS design will be implemented using the guidance from NUREG–0737, Supplement 1; NUREG–1342; and NUREG–0700, Revision 2, Section 5. The SPDS variables that are displayed in the CR will be available in the TSC and EOF as well.

Based on the above, the staff finds the HSI Design Plan's treatment of the NUREG–0700, Section 5 guidelines acceptable. Accordingly, the staff finds the HSI Design Plan's treatment of the SPDS design acceptable.

18.8.3.3 *Relationship to Other Documents*

18.8.3.3.1 DCD Tier 1, Section 3.3, "Human Factors Engineering"

DCD Tier 1, Revision 9, Table 3.3-2, contains the Tier 1 ITAAC developed by the applicant for HFE. Table 3.3-2 contains 10 items, one for each element of NUREG–0711 (except HFE program management, procedures and training) plus one item that addresses integrated system validation scenarios. Each item in Table 3.3-2 is linked to the corresponding ESBWR IP. As described in Section 14.3.9 of this report, DCD Tier 1, Section 3.3 provides ITAAC sufficient to confirm that applicable HFE elements are completed in accordance with their respective IPs,

which includes confirming that the HSI Design is completed in accordance with the IP (NEDO-33268, Revision 5), which the staff has reviewed and approved.

18.8.3.3.2 DCD Tier 2, Section 18.8, “Human-System Interface Design”:

In RAI 18.8-49, the staff identified that the HSI design methodology presented in NEDO-33268, Revision 2, was not consistent with the methodology summarized in DCD Tier 2, Revision 3, Section 18.8. For example, the IP described three major activities: concept design, style guide development, and detailed design and integration; while the DCD did not address concept design. RAI 18.8-49 was being tracked as an open item in the SER with open items. In its response, the applicant explained that, while different terminology is used, the DCD does address concept design. In addition, the applicant rewrote DCD Tier 2, Revision 5, Section 18.8, to address the staff’s concerns. The staff finds the revised Section 18.8 acceptable because the IP and the DCD are now consistent. Based on the applicant’s response and revisions to the DCD, RAI 18.8-49 is resolved.

DCD Tier 2, Revision 9, Section 18.8, provides a high-level description of the ESBWR HSI design process. This section of the DCD also references the detailed IP (NEDE-33268P, Revision 5), which is designated as Tier 2*. As discussed above in Section 18.8.3 of this report, NEDO-33268, Revision 5 describes an HSI design process which addresses the NUREG–0711 criteria for HSI design. Thus, Tier 2 together with the referenced IP provides an acceptable description of the ESBWR HSI design process.

18.8.4 Conclusions

The staff reviewed the HSI design at an IP level (see Section 18.1.4 of this report for a discussion of review levels) using the review criteria in Section 8.4 of NUREG–0711. For the reasons set forth above the staff concludes that the ESBWR HSI design process, as described in NEDE-33268P, Revision 5, provides an acceptable methodology to (1) develop HSI design inputs and identify and refine HSI designs; and (2) translate functional and task requirements to the detailed design of CDAs and other aspects of the HSI through the systematic application of HFE principles and criteria. DCD Tier 1, Revision 9, Section 3.3, provides ITAAC sufficient to confirm that the HSI design is completed in accordance with the IP (NEDE-33268P, Revision 5), which the staff has reviewed and approved. Accordingly, the staff concludes that the applicant’s HSI design is acceptable at the IP level.

18.9 Procedure Development

18.9.1 Regulatory Criteria

With the exception of criterion 7 in NUREG–0711, which is related to computer based procedures (CBPs), the staff’s evaluation of the applicant’s procedure program is addressed in Section 13.5 of this report. It has not been included here to avoid redundancy and confusion. With the exception of criterion 7, NUREG–0711 criteria addressing procedure development are a subset of the review criteria contained in the regulatory guidance associated with SRP Section 13.5 which provides guidance on the development and implementation of plant procedures.

In addition to NUREG–0711, Revision 2, the staff also used the following guidance documents for the review of CBPs:

- NUREG–0700
- DI&C-ISG-05, “Highly-Integrated Control Rooms—Human Factors Issues,” Revision 1, November 3, 2008

18.9.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.9 describes the ESBWR procedure development. DCD Tier 2, Revision 9, Section 18.9, incorporates by reference NEDE-33217P, Revision 6, and NEDO-33274, Revision 5, “ESBWR Human Factors Engineering Procedures Development Implementation Plan.”

18.9.3 Staff Evaluation

NUREG–0711 review criteria 1 through 6 and 8 through 9 are associated with the applicant’s procedure program, which is addressed in Section 13.5 of this report. Therefore, NUREG–0711 review criteria 1-6 and 8-9 are not addressed below. The staff reviewed the use of CBPs using criterion 7 of NUREG–0711, and applicable guidance in NUREG–0700 and DI&C-ISG-05. This review is limited to the HFE design of the CBP interface. It does not address the procedures that are incorporated into the CBP interface.

18.9.3.1 NUREG–0711 Review Criteria

- (7) An analysis should be conducted to determine the impact of providing CBPs and to specify where such an approach would improve procedure utilization and reduce operating crew errors related to procedure use. The justifiable use of CBPs over paper procedures should be documented. An analysis of alternatives in the event of loss of CBPs should be performed and documented.

Evaluation of Criterion (7)

DCD Tier 2, Revision 9, provides a brief discussion of CBPs and references the procedures IP. NEDO-33274, Revision 5, describes the approach to using CBPs and paper backup procedures to operate the ESBWR. NEDO-33274, Revision 5, Section 4.1.3.4, states that, unless the iterative HFE processes shown in Figure 2 dictate otherwise, CBPs are the normal presentation medium for all plant procedures. Duplicate paper-based procedures will provide backup in the event CBPs are not available. CBPs and paper-based procedures are created, revised, and validated using the processes in NEDO-33274, Revision 5.

Section 4.1.3.4 also states that the ESBWR style guide specifies HSI requirements for CBPs and that the appropriate procedure writer’s guide specifies the formatting and content for the CBPs. Section 3.1.4 states that procedures are inputs to the V&V process where they are evaluated to ensure that they meet all necessary attributes.

Based on ongoing technology development, the use of CBPs with paper backups is a generally accepted approach. The NRC has also developed guidance for the evaluation of CBPs in NUREG–0700, Section 8, and DI&C-ISG-05, Criteria 25 through 30. Hence, the staff did not expect the applicant to provide the specific types of analyses identified in the criterion, but rather the information described above.

NEDO-33274, Revision 5, Section 1, "Overview," states that hardcopy procedures are developed and maintained for use in the event that the CBP system is lost. CBP and hardcopy procedures are developed and written in a coordinated manner to facilitate the smooth transition between the two presentation mediums. NEDO-33274, Section 4.1.3.1, states that writer's guide requirements and guidelines will insure that CBP and hardcopy procedures are developed and written in a coordinated manner to facilitate the smooth transition between the two presentation mediums. Section 4.1.3.3 states that V&V testing and evaluations ensure that CBPs and hardcopy procedures can be effectively performed as written. CBPs and hardcopy procedures for the same tasks are verified to be similarly written, presented, and performed. The philosophy and methods of transitioning between CBPs and hardcopy procedures that are built into the HSI are verified to support smooth transitions. This verification includes both planned transitions to and from CBPs and unplanned transitions from CBPs to hardcopy procedures due to CBP system degradation or failure. The proposed activities for back-up procedures conform to Criteria 25 through 30 of DI&C-ISG-05. Based on the above, the staff finds the Procedures Development Plan treatment of the CBPs acceptable.

18.9.3.2 Relationship to Other Documents

There is no ITAAC for the operational programs, and, therefore, there is no interface with the DCD Tier 1 ITAAC.

DCD Tier 2, Revision 9, Section 18.9, describes procedure development implementation activities. Section 18.9 references NEDO-33274, Revision 5.

18.9.4 Conclusions

The staff reviewed the ESBWR plan for using CBPs and concludes that it conforms to all applicable regulatory guidance as described above.

18.10 Training Program Development

18.10.1 Regulatory Criteria

The staff's evaluation of the applicant's training program is addressed in Section 13.2 of this report. It has not been included here to avoid redundancy and confusion. NUREG-0711 criteria addressing training are a subset of the review criteria contained in the regulatory guidance associated with SRP Section 13.2 which provides guidance on the description and scheduling of the training program for reactor operators and senior reactor operators.

18.10.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.10, describes the ESBWR training program development. DCD Tier 2, Revision 9, Section 18.10 incorporates by reference NEDE-33217P, Revision 6, and NEDO-33275, Revision 4, "ESBWR Human Factors Engineering Training Development Implementation Plan."

18.10.3 Staff Evaluation

The staff's evaluation of the applicant's training program is addressed in Section 13.2 of this report.

There is no ITAAC for the operational programs, and, therefore, there is no interface with the DCD Tier 1 ITAAC.

18.10.4 Conclusions

The staff's conclusions on the applicant's training program are documented in Section 13.2 of this report.

18.11 Human Factors Verification and Validation

18.11.1 Regulatory Criteria

The objective of reviewing human factors V&V is to verify the following:

- The applicant has identified a sample of operational conditions that (1) includes conditions that are representative of the range of events that could be encountered during operation of the plant, (2) reflects the characteristics that are expected to contribute to system performance variation, and (3) considers the safety significance of HSI components. These sample characteristics are best identified through the use of a multidimensional sampling strategy to provide reasonable assurance that V&V evaluations include variation along important dimensions.
- The applicant's HSI inventory and characterization accurately describe all HSI displays, controls, and related equipment that are within the defined scope of the HSI design review.
- The applicant has verified that the HSI provides all alarms, information, and control capabilities needed for personnel tasks.
- The applicant has verified that the characteristics of the HSI and the environment in which it is used conform to HFE guidelines.
- The applicant has validated the integrated system design (i.e., hardware, software, and personnel elements) using performance-based tests to determine whether it acceptably supports safe operation of the plant.
- The applicant's HED evaluation acceptably prioritizes HEDs in terms of their need for improvement and the applicant develops design solutions and a realistic schedule for implementation to address those HEDs selected for correction.

One element of V&V, integrated system validation, interfaces with operational programs. Various types of operating procedures (e.g., normal, abnormal, emergency, maintenance) are used by the operators to respond to scenarios that are run on a full scope simulator. By running these scenarios, the HSIs are tested under a variety of conditions. Deficiencies and potential improvements are identified, documented and resolved with the end result being a complete HFE design capable of supporting safe plant operation. While the primary purpose of the integrated system validation is not to test the procedures, the opportunity is used to assess whether procedures can be improved and provide a better solution to validation deficiencies than what an HFE design modification would provide. Similarly operator training is relied on to provide the operators participating in the validation test with knowledge of general plant operations and a good knowledge of controls and control board layout. While the primary purpose of the integrated system validation is not to test the operators' ability, the opportunity is

used to assess whether training can be improved and provide a better solution to validation deficiencies than what an HFE design modification would provide.

To review the applicant's V&V plan, the staff used the criteria in NUREG-0711, Section 11.4.

18.11.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.11 describes the ESBWR HFE V&V. DCD Tier 2, Revision 9, Section 18.11, incorporates by reference NEDE-33276P, Revision 4, "ESBWR HFE Verification and Validation Implementation Plan." The staff also reviewed the following ESBWR documents:

- NEDO-33276
- ESBWR DCD Tier 1, Revision 9, Section 3.3
- GEH responses to RAIs 18.11-1 through 18.11-37

18.11.3 Staff Evaluation

The staff identified that significant portions of NEDO-33276, Revision 1, were written as a programmatic description rather than an IP and therefore could not be reviewed at an IP level. In RAI 18.11-36, the staff requested that the applicant provide a detailed IP for V&V rather than a programmatic description of V&V. RAI 18.11-36 was being tracked as an open item in the SER with open items. In response, the applicant indicated that it would provide information to support an IP level of review through the resolution of the remaining RAIs related to DCD Tier 2, Section 18.11. The applicant provided the level of detail necessary to address these RAIs primarily by incorporating information from its procedures (work instructions) into the IP. As described below, the applicant provided sufficient information to address the NUREG-0711 review criteria and to support an IP level of review. The staff confirmed NEDE-33276P, Revision 2, included the proposed changes.

At an IP level of review, an applicant needs to provide a detailed methodology for developing integrated system validation scenarios and the actual scenarios. Actual scenarios are needed to ensure that integrated system validation produces repeatable results. However, with the information discussed above, the applicant still did not provide actual integrated system validation scenarios to complete the IPs. As an alternative, the applicant proposed an ITAAC to develop actual scenarios by adding Design Commitment 12 in DCD Tier 1, Section 3.3, Table 3.3-2. Design Commitment 12 states the following:

Integrated system validation scenarios are developed that incorporate detailed information related to sampling dimensions, scenario identification, scenario definition, simulation of remote actions, performance measurement characteristics, performance measurement selection, performance measurement criteria, test design, and data analysis.

The ITAAC acceptance criteria state the following:

The integrated system validation scenarios were developed in accordance with the HF V&V implementation plan and meet the review criteria in the following sections of NUREG-0711, Rev. 2:

- 11.4.1.2.1, Sampling Dimensions

- 11.4.3.2.2, Validation Test Beds
- 11.4.3.2.4, Scenario Definition
- 11.4.3.2.5, Performance Measurement
- 11.4.3.2.6, Test Design
- 11.4.3.2.7, Data Analysis and Interpretation

The staff finds the above use of ITAAC acceptable. As described in the following sections, the applicant has provided an acceptable methodology for developing integrated system validation scenarios. Regarding actual scenarios, the applicant identified that selection and definition of scenarios are predicated on the output of the HFE design process (i.e., producing results from other HFE IPs). The detailed methodologies for developing integrated system validation scenarios as accepted below provide reasonable assurance that the resulting scenarios will result in repeatable integrated system validation. In addition, the use of ITAAC ensures that actual scenarios are produced and made available as a well-defined product. Therefore, providing the actual scenarios through the ITAAC is acceptable. The staff confirmed that DCD Tier 1, Revision 8, included the above ITAAC.

Accordingly, based on the staff evaluation of the applicant's response, the revision to NEDO-33276 and the ITAAC for integrated system validation scenarios, RAI 18.11-36 is resolved.

In addition, this section also addresses related documents (i.e., DCD Tier 1 and Tier 2 information).

As previously noted, the staff performed an IP level of review, as described in NUREG-0711 and Section 18.1 of this report. This section presents an evaluation of the applicant's V&V activities with respect to the applicable review criteria from NUREG-0711 (reproduced below). V&V review sections and topics include the following:

- Operation condition sampling (three review topics)
 - Sampling dimensions (three review criteria)
 - Identification of scenarios (two review criteria)
 - Special considerations for plant modernization programs (four review criteria of which none are applicable)
- Design verification (three review topics)
 - Inventory and characterization (three review criteria)
 - HSI task support verification (six review criteria of which five are applicable)
 - HFE design verification (four review criteria of which three are applicable)
- Integrated system validation (ISV) (nine review topics)
 - Test objectives (one review criterion)
 - Validation testbeds (nine review criteria)
 - Plant personnel (four review criteria)
 - Scenario definition (three review criteria)
 - Performance measurement (five review criteria)
 - Test design (nine review criteria)
 - Data analysis and interpretation (five review criteria)
 - Validation conclusions (two review criteria)

- HED resolution (seven review criteria of which six are applicable)

The criteria not applicable to the ESBWR safety review are those addressing V&V of plant modifications.

18.11.3.1 NUREG–0711 Review Criteria

18.11.3.1.1 Operational Conditions Sampling

NUREG–0711, Section 11.4.1, states the following:

The sampling methodology will identify a range of operational conditions to guide V&V activities. The review of operational conditions sampling considers the dimensions to be used to identify and select conditions and their integration into scenarios

NEDE-33276P, Revision 4, Section 4, discusses operational condition sampling (OCS).

18.11.3.1.1.1 Sampling Dimensions

In RAI 18.11-3 and its supplements, the staff requested that the applicant provide detailed implementation information for sampling dimensions rather than a programmatic description, including providing the method to be used to select the set of operational conditions supporting the sampling dimensions described in NEDO-33276. RAI 18.11-3 was being tracked as an open item in the SER with open items. In its responses, the applicant provided the level of detail to address sampling dimensions primarily by incorporating information from its procedures (work instructions) into the IP. As described below, the staff determined that the applicant provided sufficient information to address the NUREG–0711 review criteria for sampling dimensions and to support an IP level of review. The staff confirmed that NEDE-33276P, Revision 2, included the proposed changes. Based on the applicant’s responses and revision to NEDE-33276P, RAI 18.11-3 is resolved.

The sampling dimensions addressed in NUREG–0711, Section 11.4.1.2, include plant conditions, personnel tasks, and situational factors known to challenge personnel performance.

NEDE-33276P, Revision 4 summarizes several areas that will provide input to OCS that include HRA/PRA, task analysis, procedures, American National Standards Institute/American Nuclear Society (ANSI/ANS) 3.5-1998, “Nuclear Power Plant Simulators for Use in Operator Training and Examination,” and HED resolutions. Section 4.3 addresses OCS for the ISV.

Section 18.11.3.1.2 of this report addresses the selection of areas for other aspects of design verification. This section will address each of the three criteria for the sampling dimensions review topic.

(1) The following plant conditions should be included:

- Normal operational events including plant startup, plant shutdown or refueling, and significant changes in operating power
- Failure events, e.g.,
 - Instrument failures (e.g., safety-related system logic and control unit, fault tolerant controller, local “field unit” for MUX system, MUX controller, and break in

MUX line) including I&C failures that exceed the design basis, such as a common mode I&C failure during an accident

- HSI failures (e.g., loss of processing and/or display capabilities for alarms, displays, controls, and computer-based procedures)
- Transients and accidents, e.g.,
 - Transients (e.g., turbine trip, loss of off-site power, station blackout, loss of all feedwater, loss of service water, loss of power to selected buses or MCR power supplies, and safety and relief valve transients)
 - Accidents (e.g., main steam line break, positive reactivity addition, control rod insertion at power, anticipated transient without scram, and various-sized loss-of-coolant accidents)
 - Reactor shutdown and cooldown using the remote shutdown system
- Reasonable, risk-significant, beyond-design-basis events, which should be determined from the plant specific PRA
- Consideration of the role of the equipment in achieving plant safety functions (as described in the plant safety analysis report) and the degree of interconnection with other plant systems. A system that is interconnected with other systems could cause the failure of other systems because the initial failure could propagate over the connections. This consideration is especially important when assessing non-class 1E electrical systems.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 4.4.1, “Inputs,” establishes the overall process for OCS that employs a representative set of conditions and tasks and weighting factors to use in the selection. Section 4.4.1.2, “Minimum Conditions and Tasks,” and other portions of Section 4.4, identify the following plant conditions that ISV scenarios will include:

- Normal operational events
- Failure events, including support system failures (electrical, cooling water, and air), nonsafety-related distributed control and information system failure, automation failure, and software display system failure
- Transients and accidents, including the use of emergency operating procedures (EOPs), abnormal operating procedures (AOPs), and alarm response procedures (ARPs) that will exercise each leg of the EOP/severe accident management guideline (SAMG) flow charts
- Risk-important PRA scenarios
- Use of various operator panels in the CR, back panels, LCSs, and the remote shutdown station

The above conditions cumulatively address the five sets of plant conditions identified in Criterion (1). Accordingly, the staff finds the V&V Plan’s treatment of the criterion for selection of plant conditions acceptable.

(2) The following types of personnel tasks should be included:

- Risk-significant HAs, systems, and accident sequences—All risk-important HAs should be included in the sample. These include [those] identified in the PRA and those identified as risk-important in the safety analysis report (SAR) and NRC's SER. Situations where human monitoring of an automatic system is risk-important should be considered. Additional factors should be sampled that contribute highly to risk, as defined by the PRA, including:
 - Dominant HA (selected via sensitivity analyses)
 - Dominant accident sequences
 - Dominant systems (selected via PRA importance measures such as Risk Achievement Worth or Risk Reduction Worth)
- OER-identified difficult tasks—The sample should include all personnel tasks identified as problematic during the applicant's review of operating experience.
- Range of procedure guided tasks—These are tasks that are well defined by normal, abnormal, emergency, alarm response, and test procedures. The operator should be able to, as part of rule-based decision-making, understand and execute the specified steps. Appendix A of RG 1.33, Revision 2, "Quality Assurance Program Requirements," issued February 1978, contains several categories of "typical safety-related activities that should be covered by written procedures." The sample should include appropriate procedures in each relevant category:
 - Administrative procedures
 - General plant operating procedures
 - Procedures for startup, operation, and shutdown of safety-related systems
 - Procedures for abnormal, off normal, and alarm conditions
 - Procedures for combating emergencies and other significant events
 - Procedures for control of radioactivity
 - Procedures for control of measuring and test equipment and for surveillance tests, procedures, and calibration
 - Procedures for performing maintenance
 - Chemistry and radiochemical control procedures
- Range of knowledge-based tasks—these are tasks that are not as well defined by detailed procedures. Knowledge-based decision-making involves greater reasoning about safety and operating goals and the various means of achieving them. A situation may [call for] knowledge-based decision-making if the rules do not fully address the problem, or the selection of [an] appropriate rule is not clear. An example in a pressurized water reactor plant may be the difficulty in diagnosing a steam generator tube rupture (SGTR) with a failure of radiation monitors on the secondary side of the plant because (1) there is no main indication of the rupture (the presence of radiation in secondary side), and (2) the other effects of the rupture (i.e., slight changes in pressures and levels on the primary and secondary sides) may be attributed to other causes. While the operators may use procedures to treat the symptoms of the event, the determination that the cause is [an] SGTR may [warrant] situation assessment based on an understanding of the plant's design and the possible combinations of failures that could result in the observed symptoms. Errors in rule-based decision-making result from selecting the wrong rule or incorrectly applying a rule. Errors in knowledge-based decision-making result from mistakes in higher-level cognitive functions such as judgment, planning, and

analysis. The latter are more likely to occur in complex failure events where the symptoms do not resemble the typical case, and thus, are not amenable to pre-established rules.

- Range of human cognitive activities—The sample should include the range of cognitive activities performed by personnel, including:
 - Detection and monitoring (e.g., of critical safety-function threats)
 - Situation assessment (e.g., interpretation of alarms and displays for diagnosis of faults in plant processes and automated control and safety systems)
 - Response planning (e.g., evaluating alternatives for recovery from plant failures)
 - Response implementation (e.g., in-the-loop control of plant systems, assuming manual control from automatic control systems, and carrying out complicated control actions)
 - Obtaining feedback (e.g., of the success of actions taken)
- Range of human interactions—The sample should reflect the range of interactions among plant personnel, including tasks that are performed independently by individual crew members and tasks that are performed by crew members acting as a team. These interactions among plant personnel should include interactions between:
 - MCR operators (e.g., operations, shift turnover walkdowns)
 - MCR operators and auxiliary operators
 - MCR operators and support centers (e.g., the technical support center and the emergency offsite facility)
 - MCR operators with plant management, NRC, and other outside organizations
- Tasks that are performed with high frequency.

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Sections 4.4.1.2 and Section 4.4.1.3, both address the selection of personnel tasks to be included in the ISV. These sections specify that the following types of tasks will be included:

- All risk significant HAs
- All safety systems
- Risk-important scenarios within the scope of the EOPs and SAMGs
- Risk-important abnormal operational occurrences
- Risk-important transients within the scope of the AOPs and ARPs
- Operationally difficult tasks from the ESBWR OER

- Tasks addressed by procedures in the following categories: administrative, normal plant operations, EOPs, AOPs, ARPs, surveillances, testing, maintenance, chemistry, and radiation control
- Knowledge-based tasks—each leg of the EOP/SAMG flow charts, support system failures, automation failures, tasks identified in the task analyses as knowledge-based
- Operation of first-of-a-kind systems in the ESBWR design
- Range of cognitive demands: detection and monitoring, diagnostic, situation assessment, decision making, planning, plant manipulations, monitoring plant response
- Range of communication demands as follows: among CR personnel, between the CR and the field, between the CR and emergency support centers, between the CR and plant management, between the CR and other agencies such as local government and the NRC

These sections cumulatively address the six types of personnel tasks identified in Criterion (2). Accordingly, the staff finds the V&V Plan's treatment of the criterion for types of personnel tasks acceptable.

- (3) The sample should reflect a range of situational factors that are known to challenge human performance, such as:
- Operationally difficult tasks—The sample should address tasks that have been found to be problematic in the operation of nuclear power plants, e.g., procedure versus situation assessment conflicts. The specific tasks selected should reflect the operating history of the type of plant being validated (or the plant's predecessor).
 - Error-forcing contexts—Situations specifically designed to create human errors should be included to assess the error tolerance of the system and the capability of operators to recover from errors should they occur.
 - High-workload conditions—The sample should include situations where human performance variation due to high workload and multitasking situations can be assessed.
 - Varying-workload situations—The sample should include situations where human performance variation due to workload transitions can be assessed. These include conditions that exhibit (1) a sudden increase in the number of signals that must be detected and processed following a period in which signals were infrequent and (2) a rapid reduction in signal detection and processing demands following a period of sustained high task demand.
 - Fatigue and circadian factors—The sample should include situations where human performance variation due to personnel fatigue and circadian factors can be assessed.
 - Environmental factors—The sample should include situations where human performance variation due to environmental conditions such as poor lighting, extreme temperatures, high noise, and simulated radiological contamination can be assessed.

Evaluation of Criterion (3)

NEDE-33276P, Revision 4, Section 4.4.1.3, addresses further the multidimensional sampling of conditions for selection of ISV scenarios. This section presents measures for addressing a range of situational factors, including the following:

- Operationally difficult tasks identified via the ESBWR OER
- Scenarios designed to generate human errors
- Scenarios with different crew sizes and containing both high and low workload situations
- Tasks to examine fatigue and circadian factors
- Tasks identified in the ESBWR task analysis as having environmental factors, such as poor lighting, high noise, or radiation

These measures cumulatively address the range of situational factors identified in Criterion (3). Accordingly, the staff finds the V&V Plan's treatment of the criterion for range of situational factors acceptable.

18.11.3.1.1.2 Identification of Scenarios

In RAI 18.11-4 and its supplements, the staff requested that the applicant provide detailed implementation information for identification of scenarios rather than a programmatic description, including the method that it will use to develop the scenarios so that they reflect the scenario characteristics described in NEDO-33276. RAI 18.11-4 was being tracked as an open item in the SER with open items. In its responses, the applicant provided the necessary level of detail to address the identification of scenarios primarily by incorporating information from its procedures (work instructions) into the IP. As described below, the staff determined that the applicant provided information sufficient to address the NUREG-0711 review criteria for identification of scenarios and to support an IP level of review. The staff confirmed NEDE-33276P, Revision 2, included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-4 is resolved.

This section of the SER addresses each of the two criteria for the identification of scenarios.

- (1) The results of the sampling should be combined to identify a set of scenarios to guide subsequent analyses. A given scenario may combine many of the characteristics identified by the operational event sampling.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 4.4.1.4, "Weighted Selection of Integrated System Validation Scenarios," describes how the results of the OCS process are combined using a weighted selection process to identify the actual scenarios for ISV. This ensures that operational diversity is met.

Accordingly, the staff finds the V&V Plan's treatment of the criterion for combining the results of sampling acceptable.

(2) The scenarios should not be biased in the direction of over representation of the following:

- Scenarios for which only positive outcomes can be expected
- Scenarios that for integrated system validation are relatively easy to conduct administratively (scenarios that place high demands, data collection or analysis are avoided)
- Scenarios that for integrated system validation are familiar and well structured (e.g., which address familiar systems and failure modes that are highly compatible with plant procedures such as “textbook” design-basis accidents)

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Section 4.4.2, “Scenario Identification and Development,” describes in some detail the structured process used to develop the actual scenarios. This section not only describes the overall objective of the scenario development, but also the detailed aspects of constructing scenarios, such as the specification of initial conditions, selecting failure events, and determining other scenario attributes, both qualitative and quantitative. Section 4.4.3, “Measures Taken to Eliminate or Control Bias,” lists techniques used to control bias, including procedurally controlled scenario development and validation, pilot studies designed to identify bias, and “backcasting” (an approach that uses both desirable and undesirable outcomes, and develops scenarios with conditions and events that vary the likelihood of reaching the outcome). After scenario development is completed, the resulting set of scenarios is evaluated to identify any of the challenges identified in this criterion.

Accordingly, the staff finds the V&V Plan’s treatment of the criterion for avoiding bias in scenario selection acceptable.

18.11.3.1.2 Design Verification

18.11.3.1.2.1 *Inventory and Characterization*

NEDE-33276P, Revision 3, Section 3.1, discusses HSI inventory and characterization.

- (1) Scope—The applicant should develop an inventory of all HSI components associated with the personnel tasks based on the identified operational conditions. The inventory should include aspects of the HSI that are used for interface management such as navigation and display retrieval in addition to those that control the plant.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 3.1.1, describes the scope of the HSI inventory characterization. The plan indicates that the scope includes the personnel tasks associated with the operational conditions defined as part of the sampling process. This includes HSIs used for interface management tasks. Accordingly, the staff finds the V&V Plan’s treatment of the criterion for inventory and characterization scope acceptable.

- (2) HSI Characterization—The inventory should describe the characteristics of each HSI component within the scope of the review. The following is a minimal set of information for the characterization:

- A unique identification code number or name

- Associated plant system and subsystem
- Associated personnel functions/subfunction
- Type of HSI component
 - Computer-based control (e.g., touch screen or cursor-operated button and keyboard input)
 - Hardwired control (e.g., J-handle controller, button, and automatic controller)
 - Computer-based display (e.g., digital value and analog representation)
 - Hardwired display (e.g., dial, gauge, and strip chart recorder)
- Display characteristics and functionality (e.g., plant variables/parameters, units of measure, accuracy of variable/parameter, precision of display, dynamic response, and display format [bar chart, and trend plot])
- Control characteristics and functionality (e.g., continuous versus discrete settings, number and type of control modes, accuracy, precision, dynamic response, and control format [method of input])
- User-system interaction and dialog types (e.g., navigation aids and menus)
- Location in data management system (e.g., identification code for information display screen)
- Physical location in the HSI (e.g., control panel section), if applicable.
- Photographs, copies of video display unit screens, and similar samples of HSI components should be included in the HSI inventory and characterization.

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Section 3.1.4, describes the approach to HSI inventory characterization. The plan specifies that the inventory characterization includes the unique identifier, plant system, personnel functions, HSI characteristics, user interaction types, location in the data management system, and the physical location. Thus the applicant's plan addresses a methodology to characterize the items in the HSI inventory identified in NUREG-0711. Accordingly, the staff finds the V&V Plan's treatment of the criterion for HSI characterization acceptable.

- (3) Information Sources—The inventory should be based on the best available information sources. Equipment lists, design specifications, and drawings describe HSI components. These descriptions should be compared by directly observing the components, both hardwired and computer-generated, to verify that the inventory accurately reflects their current state.

Evaluation of Criterion (3)

NEDE-33276P, Revision 4, Section 3.1.3 identifies the inputs and includes software design requirements established during task analysis as well as task analysis, HSI design and other design engineering documents. The applicant's methodology for inventory development specifies the inclusion of photographs, video display unit screens, and similar samples of HSI components as part of the inventory. This provides assurance that the subsequent V&V

activities are based on an inventory reflecting the current state of the HSI. Accordingly, the staff finds the V&V Plan's treatment of the criterion for inventory information sources acceptable.

18.11.3.1.2.2 Human-System Interface Task Support Verification

NEDE-33276P, Revision 4, Section 3.2, discusses HSI task support verification.

- (1) **Criteria Identification**—The criteria for Task Support Verification come from task analyses of HSI requirements for performance of personnel tasks that are selected operational conditions should be defined. [That is, the criteria for Task Support Verification are the HSI requirements identified by task analysis.]

Evaluation of Criterion (1)

In RAI 18.11-7 and its supplements, the staff requested that the applicant clarify the criteria used in task support verification, including criteria used to evaluate the HSIs that support tasks. RAI 18.11-7 was being tracked as an open item in the SER with open items. In its responses, the applicant provided a detailed description of the task support verification methodology. As described below, the staff finds that the applicant provided information sufficient to address the NUREG-0711 review criterion for the criteria used to identify scenarios. The staff confirmed that NEDE-33276P, Revision 2 included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-7 is resolved.

NEDE-33276P, Revision 4, Section 3.2.4, discusses the methods and procedures for conducting task support verification. It indicates that HSIs are evaluated with respect to the need for HSIs identified in task analysis and provides a detailed breakdown into the aspects of the tasks that are considered. These include task-level objectives and task accomplishments as well as individual task steps.

Accordingly, the staff finds the V&V Plan's treatment of the criterion for task support verification criteria identification acceptable.

- (2) **General Methodology**—The HSIs and their characteristics (as defined in the HSI inventory and characterization) should be compared to the personnel task requirements identified in the task analysis.

Evaluation of Criterion (2)

In RAI 18.11-8 and its supplements, the staff requested that the applicant clarify the organizational responsibilities for HSI task support verification and explain why the evaluation appeared limited to drawings and computer generated displays. RAI 18.11-8 was being tracked as an open item in the SER with open items. The applicant indicated the HFE design team is responsible for task support verification. The applicant also indicated that the NEDO contains an expanded scope for this analysis, which includes CDAs. As described below, the staff finds that the applicant provided information sufficient to address the NUREG-0711 review criterion for the general methodology for task support verification. The staff verified that NEDE-33276P, Revision 2, contained the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-8 is resolved.

NEDE-33276P, Revision 4, Section 3.2.4, presents the applicant's methodology. The methodology involves comparing the ESBWR HSIs to the personnel task specifications

identified in task analysis. This will be accomplished using several available tools, such as full-scope and part-task simulators and computer-generated displays.

Accordingly, the staff finds the V&V Plan's treatment of the methodology for task support verification acceptable.

(3) Task Requirements Deficiencies—HEDs should be identified when:

- An HSI needed for task performance (e.g., a [needed] control or display) is not available
- HSI characteristics do not match the personnel task requirements, e.g., a display shows the necessary plant parameter but not the range or precision needed for the task.

Evaluation of Criterion (3)

NEDE-33276P, Revision 4, Section 3.2.5, identifies the conditions for identifying HEDs. These include tasks that are unsupported by HSIs (e.g., a needed alarm is not available), partially supported tasks (e.g., when an HSI does not meet all the task demands), and HSI characteristics that do not match personnel task specifications (e.g., a display that provides a necessary plant parameter, but is not of the precision needed for the task). Accordingly, the staff finds the V&V Plan's treatment of the criterion for task requirement HED identification acceptable.

(4) Unnecessary HSI Components—An HED should be identified for HSIs that are available in the HSI but are not needed for any task. Unnecessary HSIs introduce clutter and can distract personnel for the selection of appropriate HSIs. It is important to verify that the HSI is actually unnecessary. Appropriate HSI components may not appear to be associated with personnel tasks for the following reasons:

- The HSI component is needed for a task that was not addressed by the task analysis (e.g., it was not within the scope of the design review).
- The task analysis was incomplete, and thus overlooked the need for the HSI component.
- The HSI component only partially meets the personnel task requirements that were established.

If an HSI component has no associated personnel tasks because the function and task analysis was incomplete, then the applicant should identify and resolve any shortcomings in that analysis.

Evaluation of Criterion (4)

NEDE-33276P, Revision 4, Section 3.2.5, identifies unnecessary HSI components as a condition warranting an HED. Such an HED is identified if an HSI is not supporting personnel tasks. Accordingly, the staff finds the V&V Plan's treatment of the criterion for identifying unnecessary HSI components acceptable.

(5) HED Documentation—HEDs should be documented to identify the HSI, the relevant task criterion, and basis for the deficiency (what aspect of the HSI has been identified as not meeting task requirements).

Evaluation of Criterion (5)

NEDE-33276P, Revision 4, Section 3.2.5, discusses the documentation of task support verification results. The documentation includes the HSIs involved, the task criteria, and the basis for any identified deficiencies. The results are maintained in the HFEITS until resolved. Accordingly, the staff finds the V&V Plan's treatment of the criterion for HED documentation acceptable.

18.11.3.1.2.3 Human Factors Engineering Design Verification

- (1) **Criteria Identification**—The criteria for this verification are the HFE guidelines. The selection of guidelines used in the review depends upon the characteristics of the HSI components included in the scope of the review, as defined in the HSI characterization. It also depends upon whether the applicant has developed a style guide (design-specific HFE guideline document). When a style guide is used by the applicant, its acceptability should be reviewed by the staff. The procedures involved are described in [NUREG–0711] Section 8.4.5. The HFE guidelines contained in NUREG–0700 may be used to support the staff's review of the guidance contained in an applicant's style guide. When an NRC reviewed style guide has been used, it can provide the criteria for HFE design verification.

When no style guide is available, the guidelines in NUREG–0700 can be used for the HFE design verification. However, since not all of these guidelines will be applicable to each review, the selection of guidelines should be based on the characteristics of the HSI components being evaluated. A subset of guidelines appropriate to the specific design implementation should be identified based on the HSI characterization.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 3.3, discusses HFE design verification. Section 3.3 indicates that this evaluation verifies that each HSI component meets the HFE guidelines contained in the ESBWR HFE style guide. Section 3.3.2, "Objectives," reinforces this and indicates that the objective of the verification is to ensure that the implemented HSI component design and environment conform to the ESBWR HFE style guide.

NEDE-33276P, Revision 4, Section 3.3.4.1, discusses the application of the criteria within the overall methodology. HFE design verification will address the individual HSI components, consistency across HSIs, panel configurations, room layouts, and environmental factors in the MCR, remote shutdown system (RSS), and risk-significant LCSs.

Accordingly, the staff finds the V&V Plan's treatment of the criterion for criteria identification acceptable.

- (2) **General Methodology**—The characteristics of the HSI components should be compared with HFE guidelines. These guidelines are applicable to different aspects of the design: task-independent features (e.g., font size), task-specific features (e.g., scale units), and task-integration features (e.g., proximity of control-display).

A single guideline may apply to many identical HSI components, especially in the case of significant HSI modifications and HSIs for new plants. In addition, some environmental considerations (e.g., lighting) may be applicable. To simplify the

application of guidelines and reduce redundancy when reporting findings, the guidelines may be applied to features of the HSI as follows:

- Global features—global HSI features are those relating to the configurational and environmental aspects of the HSI, such as MCR layout, general workstation configuration, lighting, noise, heating, and ventilation. These aspects of the review, e.g., MCR lighting, tend to be evaluated only once.
- Standardized features—standardized features are those that were designed using HFE guidelines applied across individual controls and displays (e.g., display screen organization, display format conventions, and coding conventions). Therefore, their implementation should be more consistent across the interface than features that were not designed with guidelines. Thus, for example, if display labeling is standardized by the applicant's HFE guidelines (style guide), which have been accepted by the NRC, then display labels can be spot-checked rather than being verified individually.
- Detailed features—detailed features are the aspects of individual HSIs that are not addressed by general HFE guidelines. The latter can be expected to be more variable than the standardized design features.

For each guideline, it should be determined whether the HSI is "acceptable" or "discrepant" from the guideline (therefore, potentially unacceptable), i.e., an HED. "Acceptable" should be indicated only if there is total compliance, i.e., only if every instance of the item is fully consistent with the criteria established by the HFE guidelines. If there is any instance of noncompliance, full or partial, then an evaluation of discrepant conditions should be given, and a notation made as to where noncompliance occurs.

Discrepancies should be evaluated as potential indicators of additional issues. For example, identifying an inappropriate format for presenting data on an individual display should be considered a potential sign that other display formats could be incorrectly used or that the observed format is inappropriately used elsewhere. As a result, the sampling strategy could be modified to encompass other display formats. In some cases, discovering these discrepancies could warrant further review in the identified areas of concern.

Evaluation of Criterion (2)

In RAI 18.11-13 and its supplements, the staff requested that the applicant clarify the methodology and acceptance criteria to be used for HFE design verification because the scope and the description of the methodology and acceptance criteria in NEDO-33276, Revision 0, were inconsistent. RAI 18.11-13 was being tracked as an open item in the SER with open items. In its responses, the applicant reorganized and augmented its description of the methodology and acceptance criteria to be used for HFE design verification. As described below, the staff finds that the applicant provided information sufficient to address the NUREG-0711 review criterion for general methodology for HFE design verification. The staff confirmed NEDE-33276P, Revision 2 included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-13 is resolved.

NEDE-33276P, Revision 4, Sections 3.3, discusses HFE design verification methodology. The general methodology is to compare HSI design features to the applicable criteria from the ESBWR HFE style guide. The verification also encompasses panel and workstation layouts, relationships between individual HSI components, HSI reach and accessibility, HSI visibility,

seating, and local environment. This is an acceptable approach to HFE design verification because it ensures design specifications have been implemented in the final design.

NEDE-33276P, Section 3.3.5, addresses the identification of HEDs. Any instance of noncompliance with the design specifications is identified as an HED. This includes partial noncompliance as well as full noncompliance. HEDs reflecting standardized features will address changes across HSIs employing that feature.

The design verification methodology described in the plan provides for a detailed comparison of the final HFE design against design specifications. Deviations are recorded, tracked and resolved. Accordingly, the staff finds the V&V Plan's treatment of the criterion for HFE design verification methodology acceptable.

- (3) HED Documentation—HEDs should be documented by the applicant in terms of the HSI component involved and how its characteristics depart from a particular guideline.

Evaluation of Criterion (3)

NEDE-33276P, Revision 4, Section 3.3.5, discusses the documentation of HEDs. Any instance of noncompliance, either full or partial, is logged into the HFEITS along with the nature of the discrepancy. Accordingly, the staff finds the V&V Plan's treatment of the criterion for HED documentation acceptable.

18.11.3.1.3 Integrated System Validation

18.11.3.1.3.1 Test Objectives

- (1) Detailed objectives should be developed to provide evidence that the integrated system adequately supports plant personnel in the safe operation of the plant. The test objectives and scenarios should be developed to address aspects of performance that are affected by the modification [of the] design, including personnel functions and tasks affected by the modification. The objectives should be to:
 - Validate the role of plant personnel.
 - Validate that the shift staffing, assignment of tasks to crew members, and crew coordination (both within the control room as well as between the control room and local control stations and support centers) is acceptable. This should include validation of the nominal shift levels, minimal shift levels, and shift turnover.
 - Validate that for each human function, the design provides adequate alerting, information, control, and feedback capability for human functions to be performed under normal plant evolutions, transients, design-basis accidents, and selected, risk-significant events that are beyond-design basis.
 - Validate that specific personnel tasks can be accomplished within time and performance criteria, with a high degree of operating crew situation awareness, and with acceptable workload levels that provide a balance between a minimum level of vigilance and operator burden. Validate that the operator interfaces minimize operator error and provide for error detection and recovery capability when errors occur.

- Validate that the crew can make effective transitions between the HSIs and procedures in the accomplishment of their tasks and that interface management tasks such as display configuration and navigation are not a distraction or undue burden.
- Validate that the integrated system performance is tolerant of failures of individual HSI features.
- Identify aspects of the integrated system that may negatively affect integrated system performance.
- For modifications that change plant systems but do not modify the HSI, validation can provide evidence about the adequacy of the existing HSIs, procedures, and training for supporting personnel performance. The staff should verify that the applicant validates that the functions and tasks allocated to plant personnel can be accomplished effectively when the integrated design is implemented.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 5.2, describes the objectives of the validation program. The 13 objectives include validation of the operator role, shift staffing, HSI support for personnel functions and tasks, time and performance criteria for personnel tasks, error tolerant features, HRA/PRA assumptions, and the other considerations identified in the staff's review criterion. Accordingly, the staff finds the V&V Plan's treatment of the criterion for test objectives acceptable.

18.11.3.1.3.2 Validation Testbeds

In RAI 18.11-19, the staff requested that the applicant clarify (1) the use of simulators in integrated system validation (review Criteria (1) through (7)); and (2) which actions outside the CR should be included in validation scenarios and how these actions will be modeled (Criterion (8)). RAI 18.11-19 was being tracked as an open item in the SER with open items. In response to item 1 concerning the use of simulators, the applicant clarified the purpose, properties, and scope of simulators to be used as testbeds to be consistent with their description in NEDO-33275. The applicant also clarified that it will use a full-scope simulator that conforms to the guidance of ANSI/ANS 3.5-1998 and RG 1.149, Revision 3, "Nuclear Power Plant Simulation Facilities for Use in Operator Training and License Examinations," issued October 2001, for integrated system validation. In its response to item 2 regarding validation scenarios, the applicant modified NEDE-33276P, Revision 4, Section 5.4.1.5, to explain how risk-important LCSs and their HSIs are addressed. Integrated system validations that call for actions to be performed at LCSs are performed utilizing action durations, simulated feedback indications in the HSI, and communication mechanisms used in the plant. Scenarios will model local tasks important to scenario timing and fidelity as well as the local tasks important to risk or safety. The staff finds that these changes adequately address the treatment of actions outside the CR because they ensure that local control actions are properly integrated into the validation scenarios. The staff confirmed that NEDE-33276P, Revision 4, contained the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-19 is resolved.

Review Criteria (1) through (7) in Section 11.4.3.2.2 of NUREG-0711 provide for the review of simulation testbed fidelity. The NUREG states that one approach to identifying a testbed that meets the staff's fidelity criteria is to ensure its compatibility with ANSI/ANS 3.5-1998. NEDE-

33276P, Revision 4, Section 5.4.1, indicates that the simulator testbed to be used for validation will conform to the guidance in ANSI/ANS 3.5-1998 as well as RG 1.149. Accordingly, the staff finds the V&V Plan's treatment of Criteria (1) through (7) pertaining to simulator fidelity acceptable. For completeness, the individual criteria are listed below.

- (1) **Interface Completeness**—The testbed should completely represent the integrated system. This should include HSIs and procedures not specifically [provided for] in the test scenarios. For example, adjacent controls and displays may affect the ways in which personnel use those that are addressed by a particular validation scenario.

Evaluation of Criterion (1)

The applicant's testbed meets this criterion by reference to ANSI/ANS 3.5-1998 and RG 1.149.

- (2) **Interface Physical Fidelity**—A high degree of physical fidelity in the HSIs and procedures should be represented, including presentation of alarms, displays, controls, job aids, procedures, communications, interface management tools, layout and spatial relationships.

Evaluation of Criterion (2)

The applicant's testbed meets this criterion by reference to ANSI/ANS 3.5-1998 and RG 1.149.

- (3) **Interface Functional Fidelity**—A high degree of functional fidelity in the HSIs and procedures should be represented. All HSI functions should be available. High functional fidelity includes HSI component modes of operation, i.e., the changes in functionality that can be invoked on the basis of personnel selection and/or plant states.

Evaluation of Criterion (3)

The applicant's testbed meets this criterion by reference to ANSI/ANS 3.5-1998 and RG 1.149.

- (4) **Environment Fidelity**—A high degree of environment fidelity should be represented. The lighting, noise, temperature, and humidity characteristics should reasonably reflect that expected. Thus, noise contributed by equipment, such as air handling units and computers should be represented in validation tests.

Evaluation of Criterion (4)

The applicant's testbed meets this criterion by reference to ANSI/ANS 3.5-1998 and RG 1.149.

- (5) **Data Completeness Fidelity**—Information and data provided to personnel should completely represent the plant systems monitored and controlled from that facility.

Evaluation of Criterion (5)

The applicant's testbed meets this criterion by reference to ANSI/ANS 3.5-1998 and RG 1.149.

- (6) **Data Content Fidelity**—A high degree of data content fidelity should be represented. The information and controls presented should be based on an underlying model that accurately reflects the reference plant. The model should provide input to the HSI in a manner such that information accurately matches that which will actually be presented.

Evaluation of Criterion (6)

The applicant's testbed meets this criterion by reference to ANSI/ANS 3.5-1998 and RG 1.149.

- (7) Data Dynamics Fidelity—A high degree of data dynamics fidelity should be represented. The process model should be capable of providing input to the HSI in a manner such that information flow and control responses occur accurately and in a correct response time; e.g., information should be provided to personnel with the same delays as would occur in the plant.

Evaluation of Criterion (7)

The applicant's testbed meets this criterion by reference to ANSI/ANS 3.5-1998 and RG 1.149.

- (8) For important actions at complex HSIs remote from the MCR, where timely and precise HA are required, the use of a simulation or mockup should be considered to verify that human performance requirements can be achieved. (For less risk-important HAs or where the HSIs are not complex, human performance may be assessed based on analysis such as task analysis rather than simulation.)

Evaluation of Criterion (8)

NEDE-33276P, Revision 4, Section 5.4.1.5, discusses the validation of risk-important local control operations. Section 5.4.3.7 discusses the use of "critical task" summaries and "safety significant tasks." The validation of risk-important local control operations is performed using simulations and mockups and verifies that the cues, indications, communications, and feedback built into the scenario guide are accurate and timely. The simulations will include all of the risk-important local control operations. The scenarios will model other local tasks that might not be risk-important, if they are important to scenario timing and fidelity. Accordingly, the staff finds the V&V Plan's treatment of the criterion for evaluating important local actions acceptable.

- (9) The testbeds should be verified for conformance to the testbed characteristics identified above before validations are conducted.

Evaluation of Criterion (9)

NEDE-33276P, Revision 4, Section 5.4.1, addresses testbed verification. Testbeds are compared to the plant design as it develops and modified for consistency. Accordingly, the staff finds the V&V Plan's treatment of the criterion for testbed fidelity acceptable.

18.11.3.1.3.3 Plant Personnel

- (1) Participants in the validation tests should be representative of actual plant personnel who will interact with the HSI, e.g., licensed operators rather than training or engineering personnel.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 5.4.2, identifies the participants in the validation exercises. The crews used are individuals trained to be ESBWR reactor operators and SROs.

Accordingly, the staff finds the V&V Plan's treatment of the criterion for participant representation acceptable.

- (2) To properly account for human variability, a sample of participants should be used. The sample should reflect the characteristics of the population from which the sample is drawn. Those characteristics that are expected to contribute to system performance variation should be specifically identified and the sampling process should provide reasonable assurance that variation along that dimension is included in the validation. Several factors that should be considered in determining representativeness include: license and qualifications, skill/experience, age, and general demographics.

Evaluation of Criterion (2)

The staff identified that NEDO-33276, Revision 1, did not address several aspects of participant selection. In RAI 18.11-21 and its supplements, the staff requested that the applicant clarify (1) how the sample of participants will account for human variability (Criterion (2)), (2) how minimum and normal crew configurations will be assembled and what they will consist of (Criterion (3)), and (3) how sampling bias will be prevented (Criterion (4)). RAI 18.11-21 was being tracked as an open item in the SER with open items. In their responses, the applicant revised NEDO-33276 to address each of these topics. As described below, the staff finds that the applicant provided sufficient information to address the NUREG-0711 review criteria for plant personnel. The staff confirmed that NEDE-33276P, Revision 2, included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-21 is resolved.

NEDE-33276P, Revision 4, Section 5.4.2.1, indicates that a sample of participants will be developed based on considerations of factors anticipated to create variability, such as license and qualifications, degree of skill and experience, age, and general demographics. NEDE-33276P, Revision 4, defines each of these factors. In addition, NEDE-33276P, Revision 4, Section 5.4.2.2, indicates that a minimum of three crews will participate in the validation exercises. Derivation of a sample using these factors and conducting tests with a minimum of three crews reasonably accounts for human variability. Accordingly, the staff finds the V&V Plan's treatment of the criterion for accounting for human variability acceptable.

- (3) In selection of personnel, consideration should be given to the assembly of minimum and normal crew configurations, including shift supervisors, reactor operators, shift technical advisors, etc., that will participate in the tests.

Evaluation of Criterion (3)

NEDE-33276P, Revision 4, Section 5.4.2.2, discusses crew configurations. Normal crews will consist of two licensed operators and an SRO. Minimal crew size will consist of two operators (one SRO and one reactor operator). Additionally, some scenarios will include a maximum crew size consisting of two licensed operators, an SRO, a shift manager, and a shift technical advisor. This provides a reasonable and acceptable variation in crew configurations. Accordingly, the staff finds the V&V Plan's treatment of crew configuration size acceptable.

- (4) To prevent bias in the sample, the following participant characteristics and selection practices should be avoided:
 - Participants who are part of the design organization

- Participants in prior evaluations
- Participants who are selected for some specific characteristic, such as using crews that are identified as good or experienced.

Evaluation of Criterion (4)

NEDE-33276P, Revision 4, Section 5.4.2.3, addresses the prevention of sample bias. The applicant identified three groups as ineligible to participate in evaluations. These three groups are participants from the design organization, those involved in prior evaluations, and participants selected on the basis of some specific biasing characteristic. Identification of these three groups conforms to the NUREG-711 guidance. Accordingly, the staff finds the V&V Plan's treatment of the participant sampling bias acceptable.

18.11.3.1.3.4 Scenario Definition

The staff identified that NEDO-33276, Revision 1, did not provide sufficient detail for scenario definition to support an IP level of review. In RAI 18.11-22 and its supplements, the staff requested that the applicant provide (1) an approach for developing validation scenarios consistent with the NUREG-0711 criteria, and (2) the specific scenarios to be run on testbeds. RAI 18.11-22 was being tracked as an open item in the SER with open items. In its responses, the applicant provided a detailed approach for developing validation scenarios. As discussed with RAI 18.11-36 in Section 18.11.3 of this report, the applicant provided an acceptable alternative approach of providing DAC for integrated system validation scenarios versus providing specific scenarios in NEDE-33276P. As described below, the staff finds that the applicant provided information sufficient to address the NUREG-0711 review criteria for scenario definition and to support an IP level of review. The staff confirmed that NEDE-33276P, Revision 2, included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-22 is resolved.

- (1) The operational conditions selected for inclusion in the validation tests should be developed in detail so they can be performed on a simulator. The following information should be defined to provide reasonable assurance that important performance dimensions are addressed and to allow scenarios to be accurately and consistently presented for repeated trials:
 - Description of the scenario and any pertinent "prior history" necessary for personnel to understand the state of the plant upon scenario start-up
 - Specific initial conditions (precise definition provided for plant functions, processes, systems, component conditions and performance parameters, e.g., similar to plant shift turnover)
 - Events (e.g., failures) to occur and their initiating conditions, e.g., time, parameter values, or events
 - Precise definition of workplace factors, such as environmental conditions
 - Task support needs (e.g., procedures and technical specifications)
 - Staffing objectives
 - Communication requirements with remote personnel (e.g., load dispatcher via telephone)

- The precise specification of what, when and how data are to be collected and stored (including videotaping requirements, questionnaire and rating scale administrations)
- Specific criteria for terminating the scenario

Evaluation of Criterion (1)

In NEDE-33276P, Revision 4, Section 4.4.2, the applicant discussed its approach to scenario development. Section 5.4.3 discusses the scenario definition process. The applicant also describes detailed procedures for developing detailed scenarios from the operating condition identified. For example, with respect to initial conditions, Section 4.4.2.2 indicates that scenarios are assigned a set of initial conditions to allow the simulated scenario to commence realistically. The conditions are the types of situations that would exist in the ESWBR at the time in the plant operating cycle in which the scenario is to take place. Additional initial conditions will be included for realism, such as tagged-out components or systems, in-progress maintenance, or testing. Some initial conditions are included that have no bearing on subsequent scenario events.

As another example, Section 4.4.2.3 describes the development of scenario events. The plan indicates that a sequence of events designed to achieve the scenario's objectives is developed. Each event either directly supports or contributes to the support of one or more objectives. Scenarios are developed so that various systems are affected by each type of event, such as degradation or failure of instruments, controls and components, major plant transients and accidents, and normal plant maneuvering. Realistic conditions limit the predictability, recognizability, and potential bias from operator expectations of scenario event timelines. Some scenarios incorporate equipment failures that cause or exacerbate problems in other systems. This practice allows validation of the operators' understanding of system and component interactions, integrated system operations, and the integrated HSI performance across a broad range of conditions.

Section 5.4.3 presents the means for documenting scenario details and includes proprietary examples of forms, instruction, and guidance associated with scenario documentation. The proprietary SER lists specific information collected to demonstrate that the information collected conforms to the NUREG criterion. The plan describes how each method for collecting data or defining scenario detail is accomplished.

The applicant's plan does not provide the results of these activities for individual scenarios. As described in Section 18.11.3 of this report, additional detail related to this criterion is developed as part of Design Commitment 12 in DCD Tier 1, Section 3.3, Table 3.3-2. Accordingly, the staff finds the V&V Plan's treatment of scenario details acceptable.

- (2) Scenarios should have appropriate task fidelity so that realistic task performance will be observed in the tests and so that test results can be generalized to actual operation of the real plant.

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Section 5.4.3, presents the means for documenting scenario details which were described in the evaluation of Criterion (1) above. The level of detail to be developed for each scenario results in a high degree of task fidelity (reflects actual operating conditions). The proprietary SER provides an example of the level of detail specified by the implementation plan to illustrate conformance to the NUREG criterion.

As described in Section 18.11.3 of this report, additional detail related to this criterion is developed as part of Design Commitment 12 in DCD Tier 1, Revision 9, Section 3.3, Table 3.3-2. Accordingly, the staff finds the V&V Plan's treatment of scenario task fidelity acceptable.

- (3) When evaluating performance associated with operations remote from the MCR, the effects on crew performance due to potentially harsh environments (i.e., high radiation) should be realistically simulated (i.e., additional time to don protective clothing and access radiologically controlled areas).

Evaluation of Criterion (3)

NEDE-33276P, Revision 4, Section 5.4.1.5, "Risk Significant Local Control Panels," indicates that integrated system validations that call for actions at LCSs are performed utilizing action durations, simulated feedback indications in the HSI, and communication mechanisms used in the plant. Scenarios will model local tasks important to scenario timing and fidelity as well as the local tasks important to risk or safety. The scenario guide, which was written to govern performance of the simulation, specifies in detail all of the factors associated with local operations. The scenario validation process verifies that remote manual action cues, indications, communications, and feedback built into the scenario guide are accurate and timely. Thus, scenarios that contain remote actions are accurately rendered and support validation of the integrated system HSI. The proprietary SER describes the method the applicant will use to account for time delays introduced by remote actions and the staff's basis for finding this method to be acceptable.

As described in Section 18.11.3 of the report, additional detail related to this criterion is developed as part of Design Commitment 12 in DCD Tier 1, Revision 9, Section 3.3, Table 3.3-2. Accordingly, the staff finds the V&V Plan's treatment of evaluating remote operations acceptable.

18.11.3.1.3.5 Performance Measurement

The review of performance measurement covers measurement characteristics, performance measure selection, and performance criteria.

18.11.3.1.3.5.1 Measurement Characteristics

- (1) Performance Measurement Characteristics—Performance measures should acceptably exhibit the following measurement characteristics to provide reasonable assurance that the measures are of good quality (it should be noted that some of the characteristics identified below may not apply to every performance measure):
 - Construct Validity—A measure should accurately represent the aspect of performance to be measured.
 - Diagnosticity—A measure should provide information that can be used to identify the cause of acceptable or unacceptable performance.
 - Impartiality—A measure should be equally capable of reflecting good as well as bad performance.
 - Objectivity—A measure should be based on phenomena that are easily observed.

- Reliability—A measure should be repeatable; i.e., if the same behavior is measured in exactly the same way under identical circumstances, the same measurement result should be obtained.
- Resolution—A measure should reflect the performance at an appropriate level of resolution, i.e., with sufficient detail to permit a meaningful analysis.
- Sensitivity—A measure's range (scale) and the frequency of measurement (how often data are collected) should be appropriate to the aspect of performance being assessed.
- Simplicity—A measure should be simple both from the standpoint of executing the tests and from the standpoint of communicating and comprehending the meaning of the measures.
- Unintrusiveness—A measure should not significantly alter the psychological or physical processes that are being investigated.

Evaluation of Criterion (1)

In RAI 18.11-23 and its supplements, the staff requested that the applicant provide additional detail on measurement characteristics supporting integrated system validation. RAI 18.11-23 was being tracked as an open item in the SER with open items. In responses to this RAI and to RAIs 18.11-24 and 18.11-26, the applicant provided a detailed discussion of measurement characteristics. As described below, the staff finds that the applicant provided sufficient information to address the NUREG-0711 review criteria for measurement characteristics and to support an IP level of review. The staff confirmed NEDE-33276P, Revision 3, included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-23 is resolved.

In NEDE-33276P, Revision 4, Section 5.4.4, the applicant described the performance measures that will be used in validation testing. The measures themselves are evaluated in the next section of this report, which concerns performance measurement selection. The description of each performance measure includes the measurement characteristics and a discussion of why it is applicable. The list of performance measures and their characteristics are proprietary. The proprietary SER uses an example of one of the measures and its associated characteristics to illustrate how the implementation plan conforms to the NUREG criteria. In general the staff finds that the applicant used the applicable characteristics from the NUREG criterion and that these measurement characteristics provide reasonable assurance that the performance measure itself will be of good quality. Measurement characteristics are identified for each measure and the staff finds them to be appropriate for each measure.

Accordingly, the staff finds the V&V Plan's treatment of the criterion for measurement characteristics acceptable.

18.11.3.1.3.5.2 Performance Measure Selection

In RAI 18.11-24 and its supplements, the staff requested that the applicant provide a hierarchal set of performance measures and their associated acceptance criteria consistent with the review criteria in NUREG-0711. RAI 18.11-24 was being tracked as an open item in the SER with open items. In its responses, the applicant provided a detailed discussion of performance measures and identified associated changes to NEDE-33276P. As described below, the staff finds that the applicant provided sufficient information to address the NUREG-0711 review

criteria for performance measurement selection and to support an IP level of review. The staff confirmed that NEDE-33276P, Revision 3, included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-24 is resolved.

In RAI 18.11-25 and its supplements, the staff requested that the applicant clarify the use of performance measures for automation, procedures, and displays because these measures do not directly correspond to the NUREG-0711 review criteria. RAI 18.11-25 was being tracked as an open item in the SER with open items. In responses to this RAI and RAI 18-11-24, the applicant provided a hierarchal set of performance measures that no longer involves separate measures for automation, procedures, and displays. As described below, the staff finds that the revised set of performance measures conforms to the NUREG-0711 criteria. The staff confirmed NEDE-33276P, Revision 3, included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-25 is resolved.

- (1) A hierarchal set of performance measures should be used which includes measures of the performance of the plant and personnel (i.e., personnel tasks, situation awareness, cognitive workload, and anthropometric/physiological factors). Some of these measures could be used as "pass/fail" criteria for validation and the others to better understand personnel performance and to facilitate the analysis of performance errors. The applicant should identify which are in each category.

Evaluation of Criterion (1)

In NEDE-33276P, Revision 4, Section 5.4.4, the applicant described the performance measures for plant-level and system-level performance, operator task performance, crew communication and coordination, situation awareness, workload, and anthropometric and physiological factors that will be used in validation testing.

The measures are divided into pass/fail and supplemental measures. The proprietary SER describes the pass/fail measures that will be used. These measures are acceptable to demonstrate that the control room staff can safely control the plant to achieve the objectives of the validation scenario. The use of supplemental measures to identify HEDs to be resolved through the HFE resolution process is appropriate since the measures selected identify opportunities to optimize the design.

Accordingly, the staff finds the V&V Plan's treatment of the criterion for hierarchal measurement acceptable.

- (2) Plant Performance Measurement—Plant performance measures representing functions, systems, components, and HSI use should be obtained.

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Section 5.4.4.1, identifies plant-level measures the applicant proposes. These measures are described in the proprietary SER. The staff finds that the measures, when met, demonstrate that the control room staff can safely control the plant within acceptable time limits to accomplish the objectives of the validation scenario. Additional plant measures accurately reflecting operating requirements are used in this application to assess HSI effectiveness. These measures will be defined for each scenario.

Another form of plant measure addresses the performance of risk significant actions from the PRA and HRA. In NEDE-33276P, Revision 4, Section 5.4.4.2, the applicant described how this measure is applied. The proprietary SER includes details on this measure. The staff finds that this measure is acceptable to validate that the control room staff can safely perform risk significant actions in scenarios within acceptable time limits to accomplish the objectives of the validation scenario.

The approach described by the applicant is comprehensive and addresses key aspects of plant performance, including risk-important actions. These measures will be developed uniquely for each scenario. NEDE-33276P provides direction for developing scenario specific measures. Examples are also included to illustrate application of the direction. The scenario-specific measures will be developed in accordance with Design Commitment 12 in DCD Tier 1, Revision 9, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for measurement of personnel tasks acceptable.

- (3) **Personnel Task Measurement**—For each specific scenario, the tasks that personnel are [needed] to perform should be identified and assessed. Two types of personnel tasks should be measured: primary (e.g., start a pump), and secondary (e.g., access the pump status display). Primary tasks are those involved in performing the functional role of the operator to supervise the plant; i.e., monitoring, detection, situation assessment, response planning, and response implementation. Secondary tasks are those personnel [need to] perform when interfacing with the plant, but which are not directed to the primary task, such as navigation and HSI configuration. This analysis should be used for the identification of potential errors of omission.
- Primary tasks should be assessed at a level of detail appropriate to the task demands. For example, for some simple scenarios, measuring the time to complete a task may be sufficient. For more complicated tasks, especially those that may be described as knowledge-based, it may be appropriate to perform a more fine-grained analysis such as identifying task components: seeking specific data, making decisions, taking actions, and obtaining feedback. Tasks that are important to successful integrated system performance and are knowledge-based should be measured in a more fine-grained approach.
 - The measurement of secondary tasks should reflect the demands of the detailed HSI implementation, e.g., time to configure a workstation, navigate between displays, and manipulate displays (e.g., changing display type and setting scale).
 - The tasks that are actually performed by personnel during simulated scenarios should be identified and quantified. (Note that the actual tasks may be somewhat different from those that should be performed). Analysis of tasks performed should be used for the identification of errors of commission.
 - The measures used to quantify tasks should be chosen to reflect the important aspects of the task with respect to system performance, such as:
 - Time
 - Accuracy
 - Frequency
 - Errors (omission and commission)
 - Amount achieved or accomplished
 - Consumption or quantity used

- Subjective reports of participants
- Behavior categorization by observers

Evaluation of Criterion (3)

NEDE-33276P, Revision 4, Section 5.4.4.3, states that, for each integrated system validation scenario, the tasks that personnel perform during the scenario are identified. Tasks identified during scenario development are assessed during scenario performance to validate that the integrated HSI adequately supports task performance. NEDE-33276P, Revision 4, describes other proprietary task performance measures to support the validation of the integrated plant and HSI design.

NEDE-33276P, Revision 4, also provides a proprietary three-part approach to personnel task measurement. The proprietary SER summarizes this plan including the measured attributes and assessment techniques to demonstrate conformance to the NUREG criterion.

This three-part approach to personnel task measurement provides a comprehensive approach to the assessment of both scenario-specific and general task performance. The first two types of task measures are developed uniquely for each scenario. NEDE-33276P provides direction for developing scenario-specific measures. Examples are also included to illustrate application of the direction. The scenario-specific measures will be developed in accordance with Design Commitment 12 in DCD Tier 1, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for measurement of personnel tasks acceptable.

- (4) Situation Awareness—Personnel situation awareness should be assessed. The approach to situation awareness measurement should reflect the current state-of-the-art.

Evaluation of Criterion (4)

NEDE-33276P, Revision 4, Section 5.4.4.5, addresses situation awareness measurement. NEDE-33276P, Revision 4, includes proprietary information identifying the technique to be used and how it is applied. The proprietary SER summarizes this information to illustrate how conformance to the NUREG criterion is accomplished. The method described in NEDE-33276P, Revision 4 to assess situation awareness of the control room staff is appropriate for use in validation tests.

This measure is developed uniquely for each scenario. NEDE-33276P provides direction for developing scenario specific-measures. Examples are also included to illustrate application of the direction. The scenario-specific measures will be developed in accordance with Design Commitment 12 in DCD Tier 1, Revision 9, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for measurement of personnel tasks acceptable.

- (5) Cognitive Workload—Personnel workload should be assessed. The approach to workload measurement should reflect the current state-of-the-art.

Evaluation of Criterion (5)

NEDE-33276P, Revision 4, Section 5.4.4.6, addresses cognitive workload. NEDE-33276P, Revision 4, includes proprietary information identifying the technique to be used and how it is

applied. The proprietary SER summarizes this information to illustrate how conformance to the NUREG criterion is accomplished. The method described in NEDE-33276P, Revision 4 to assess the workload of the control room staff is appropriate for use in validation tests. Accordingly, the staff finds the V&V Plan's treatment of the criterion for measurement of workload acceptable.

- (6) **Anthropometric and Physiological Factors**—Anthropometric and physiological factors include such concerns as visibility of indications, accessibility of control devices, and ease of control device manipulation that should be measured where appropriate. Attention should be focused on those aspects of the design that can only be addressed during testing of the integrated system, e.g., the ability of personnel to effectively use the various controls, displays, workstations, or consoles in an integrated manner.

Evaluation of Criterion (6)

NEDE-33276P, Revision 4, Section 5.4.4.7, addresses the measurement of anthropometric and physiological factors. The plan states that the primary evaluation of these factors is a part of the design verification. Validation tests also verify these factors have no significant negative impact on crew performance and that no problems arise during HSI use that may not have been evident when HSI components were verified without reference to specific tasks. The applicant will use a combination of observations by test personnel and post-scenario questions to assess the acceptability of anthropometric and physiological parameters. These include reach and accessibility of control devices, ease of control, visibility of indications, and seating comfort. Operator debriefing comments will also be obtained concerning these aspects of the design. These measures will provide for a comprehensive assessment of these factors.

Accordingly, the staff finds the V&V Plan's treatment of the criterion for measurement of anthropometric and physiological factors acceptable.

18.11.3.1.3.5.3 Performance Criteria

This section includes two NUREG-0711 review criteria: one addressing specific criteria for each performance measurement and the other addressing the basis for the criteria. For continuity of discussion, the evaluation section of Criterion (1) addresses both.

- (1) Criteria should be established for the performance measures used in the evaluations. The specific criteria that are used for decisions as to whether the design is validated or not should be specified and distinguished from those being used to better understand the results.

Evaluation of Criterion (1)

In RAI 18.11-26 and its supplements, the staff requested that the applicant provide specific acceptance criteria for performance measures used in deciding whether the design is validated or not. RAI 18.11-26 was being tracked as an open item in the SER with open items. In its responses to this RAI and RAI 18.11-24, the applicant discussed in detail the acceptance criteria associated with performance measures and identified associated changes to NEDE-33276P. As described below, the staff finds that the applicant provided information sufficient to address the NUREG-0711 review criteria for performance criteria and to support an IP level of review. The staff confirmed that NEDE-33276P, Revision 3, included the proposed changes.

Based on the applicant's responses and the revision to NEDE-33276P, RAI 18.11-25 is resolved.

Plant measures are both pass/fail and supplemental measures. Tested attributes (HSIs, procedures, training elements, etc.) that do not meet pass/fail criteria constitute a failure of the scenario being validated. The bases for the criteria identified are "requirements referenced" (i.e., operating specifications for system, subsystem, and operator performance defined through engineering analysis). NEDE-33276P, Revision 4, Section 5.4.4.1 and 5.4.4.2 state specific proprietary pass/fail measures that are summarized in the proprietary SER. These measures are acceptable to validate that the control room staff can safely control the plant and perform risk-significant actions in scenarios within acceptable time limits to accomplish the objectives of the validation scenario. Scenarios that exceed established acceptance limits result in integrated system validation failure.

This is an appropriate approach to criteria determination and the use of key measures as pass/fail criteria.

Task measures consist of both pass/fail and supplemental measures used to better understand personnel performance. NEDE-33276P, Section 5.4.4.3, contains a proprietary description of how success and failure criteria for task measures are developed and evaluated. In general the criteria are specific and quantifiable. The proprietary SER summarizes this material so there is specific information as to how the V&V Plan conforms to the NUREG criterion. The approach described provides reasonable criteria to define acceptable and unacceptable performance and the need for corrective actions.

The situation awareness measure is supplemental. NEDE 33276P, Section 5.4.4.5, contains a proprietary description of how success and failure criteria for the situation awareness measure is developed and evaluated. In general the criteria are specific and quantifiable. The proprietary SER summarizes this material so there is specific information as to how the V&V Plan conforms to the NUREG criterion. This approach to identifying situation assessment criteria is reasonable and appropriate.

Workload is a supplemental measure. NEDE 33276P, Section 5.4.4.6, contains a proprietary description of how success and failure criteria for the workload measure is developed and evaluated. In general the criteria are specific and quantifiable. The proprietary SER summarizes this material so there is specific information as to how the V&V Plan conforms to the NUREG criterion. This approach to identifying workload criteria is a reasonable and appropriate approach.

Anthropometric and physiological factors are a supplemental measure. The criteria identified are expert-judgment referenced. HEDs are generated when anthropometric and physiological factors negatively impact task performance or represent a risk to operator safety or well-being. This is an appropriate approach to criteria determination for this category of measure.

For the reasons discussed above, the criteria identified for each category of performance measurement provide reasonable standards against which to evaluate performance. Accordingly, the staff finds the V&V Plan's treatment of the criterion for criteria specification and their bases acceptable.

- (2) The basis for criteria should be defined, e.g., requirement-referenced, benchmark referenced, normative referenced, and expert-judgment referenced.

Evaluation of Criterion (2)

The evaluation for Criterion (1) also addresses Criterion (2). Since the staff finds Criterion (1) satisfied, as discussed above, the staff finds the V&V Plan's treatment of the criterion for criteria bases acceptable.

18.11.3.1.3.6 Test Design

The staff identified that NEDO-33276, Revision 1, did not address several aspects of test design sufficiently to support an implementation level of review. In RAI 18.11-27 and its supplements, the staff requested that the applicant describe the methodology used for certain aspects of test design. These aspects include presentation of scenarios to crews, test procedures, training of test conductors and participants, and pilot studies. RAI 18.11-27 was being tracked as an open item in the SER with open items. In its responses, the applicant revised NEDO-33276 to address each of these topics. As described below, the staff finds that the applicant provided information sufficient to address the NUREG-0711 review criteria for test design and to support an IP level of review. The staff confirmed that NEDE-33276P, Revision 3, included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-27 is resolved.

The staff considered five review criteria for test design—coupling crews and scenarios, test procedures, training of test conductors, training of test participants, and conduct of pilot studies.

18.11.3.1.3.6.1 Coupling Crews and Scenarios

- (1) Scenario Assignment—Important characteristics of scenarios should be balanced across crews. Random assignment of scenarios to crews is not recommended. The value of using random assignment to control bias is only effective when the number of crews is quite large. Instead, the validation team should attempt to provide each crew with a similar and representative range of scenarios.

Evaluation of Criterion (1)

In RAI 18.11-28, the staff requested that the applicant clarify the reuse of scenarios with the same crew. Specifically, the concern was that if a crew is subject to the same scenario twice, the crew may recognize the scenario and any data collected may be invalid. RAI 18.11-28 was being tracked as an open item in the SER with open items. In response, the applicant added a discussion of scenario assignment and sequencing in NEDE-33276P. The applicant also clarified that an individual scenario would be presented to the same crew only under exceptional circumstances. As described below, the staff finds that the applicant provided sufficient information to address the NUREG-0711 review criteria for scenario assignment. The staff confirmed that NEDE-33276P, Revision 2, included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-28 is resolved.

NEDE-33276P, Revision 4, Section 5.4.5.1 addresses the presentation of scenarios to crews. With respect to scenario assignment, the applicant indicated that scenarios will be balanced across crews to ensure that each crew receives a representative range of scenarios. NEDE-33276P, Revision 4, Section 4.4.4, provides detailed proprietary procedures for accomplishing the balance. The proprietary SER summarized the procedures to demonstrate conformance to this NUREG criterion. This process results in a reasonable distribution of scenarios for each

crew and is, therefore, acceptable. In addition, the methodology supports the identification of the impact of crew variability.

NEDE-33276P, Revision 4 provides an acceptable methodology for scenario assignments. Specific scenario assignments will be developed in accordance with Design Commitment 12 in DCD Tier 1, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report.

Accordingly, the staff finds the V&V Plan's treatment of the criterion for scenario assignments acceptable.

- (2) Scenario Sequencing—The order of presentation of scenario types to crews should be carefully balanced to provide reasonable assurance that the same types of scenarios are not always being presented in the same linear position, e.g., the easy scenarios are not always presented first.

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Section 5.4.5.1, indicates that the order in which scenarios are presented to crews will be balanced. Balancing of scenarios is discussed in the previous criterion.

In view of the foregoing, NEDE-33276P, Revision 4, provides an acceptable methodology for the development of scenario sequencing. The specific scenario sequencing will be developed in accordance with Design Commitment 12 in DCD Tier 1, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for scenario sequencing acceptable.

18.11.3.1.3.6.2 Test Procedures

- (1) Detailed, clear, and objective procedures should be available to govern the conduct of the tests. These procedures should include:
 - The identification of which crews receive which scenarios and the order that the scenarios should be presented.
 - Detailed and standardized instructions for briefing the participants. The type of instructions given to participants can affect their performance on a task. This source of bias can be minimized by developing standard instructions.
 - Specific criteria for the conduct of specific scenarios, such as when to start and stop scenarios, when events such as faults are introduced, and other information discussed in Section 11.4.3.2.4, Scenario Definition.
 - Scripted responses for test personnel who will be acting as plant personnel during test scenarios. To the greatest extent possible, responses to communications from operator participants to test personnel (serving as surrogate for personnel outside the control room personnel) should be prepared. There are limits to the ability to preplan communications since personnel may ask questions or make requests that were not anticipated. However, efforts should be made to detail what information personnel outside the control room can provide, and script the responses to likely questions.

- Guidance on when and how to interact with participants when simulator or testing difficulties occur. Even when a high-fidelity simulator is used, the participants may encounter artifacts of the test environment that detract from the performance for tasks that are the focus of the evaluation. Guidance should be available to the test conductors to help resolve such conditions.
- Instructions regarding when and how to collect and store data. These instructions should identify which data are to be recorded by:
 - Simulation computers
 - Special purpose data collection devices (such as situation awareness data collection, workload measurement, or physiological measures)
 - Video recorders (locations and views)
 - Test personnel (such as observation checklists)
 - Subjective rating scales and questionnaires
- Procedures for documentation, i.e., identifying and maintaining test record files including crew and scenario details, data collected, and test conductor logs. These instructions should detail the types of information that should be logged (e.g., when tests were performed, deviations from test procedures, and any unusual events that may be of importance to understanding how a test was run or interpreting test results) and when it should be recorded.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 5.4.5.2, addresses test procedures. It provides a high-level methodology for developing detailed procedures for individual scenarios. As part of Criterion (2) above in Section 18.11.3.1.3.6.1 of this report, scenario order is discussed and evaluated. Standardized instructions will be developed for each scenario. The proprietary SER contains a description of these instructions. The staff finds that the instructions identified important conditions of the scenario and established protocol for data collection, observer interactions, and unanticipated events.

In view of the above, NEDE-33276P, Revision 4 provides an acceptable methodology for test procedure development. The specific test procedures will be developed in accordance with Design Commitment 12 in DCD Tier 1, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for test procedures acceptable.

- (2) Where possible, test procedures should minimize the opportunity of tester expectancy bias or participant response bias.

Evaluation of Criterion (2)

In regard to minimizing bias, NEDE-33276P, Revision 4 describes plans to use well-developed procedures for the test program. NEDE-33276P, Revision 4 identifies several proprietary actions, including protocol for observer interaction, which will be taken to minimize bias. The proprietary SER lists these actions.

NEDE-33276P, Revision 4, provides an acceptable methodology for minimizing bias in test procedures. The specific procedures will be developed in accordance with Design Commitment

12 in DCD Tier 1, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for minimizing test bias acceptable.

18.11.3.1.3.6.3 Test Personnel Training

- (1) Test administration personnel should receive training on:
- The use and importance of test procedures
 - Experimenter bias and the types of errors that may be introduced into test data through the failure of test conductors to accurately follow test procedures or interact properly with participants
 - The importance of accurately documenting problems that arise in the course of testing, even if due to test conductor oversight or error

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 5.4.5.3 indicates that test personnel receive training on coordination of simulator sessions, observation and evaluation of operator performance, use of test procedures, experimenter bias, problem documentation, crew interaction, use of data collection tools, and note taking. NEDE-33276P, Revision 4, further states that the training will be accomplished in accordance with the National Academy for Nuclear Training, "Guidelines for Instructor Training and Qualifications" (ACAD 97-014). Based on the scope of the training program and the use of an accepted industry standard for accomplishing the training, the plan provides an acceptable approach to the training of test personnel. Accordingly, the staff finds the V&V Plan's treatment of the criterion for test personnel training acceptable.

18.11.3.1.3.6.4 Participant Training

- (1) Participant training should be of high fidelity; i.e., highly similar to that which plant personnel will receive in an actual plant. The participants should be trained to provide reasonable assurance that their knowledge of plant design, plant operations, and use of the HSIs and procedures is representative of experienced plant personnel. Participants should not be trained specifically to perform the validation scenarios.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 5.4.5.3, addresses training of test participants. The plan indicates that operators will receive formal classroom training as well as simulator training prior to participation. The training will be similar to existing BWR operator license training. All participants undergo comprehensive examination in a full-scope simulator covering job performance measures. Accordingly, the staff finds the V&V Plan's treatment of the criterion for high-fidelity training of participants acceptable.

- (2) Participants should be trained to near asymptotic performance (i.e., stable, not significantly changing from trial to trial) and tested prior to conducting actual validation trials. Performance criteria should be similar to that which will be applied to actual plant personnel.

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Section 5.4.5.3 addresses training of test participants. All participants will undergo a comprehensive examination in a full-scope simulator covering job performance measures. NEDE-33276P, Revision 4, further indicates that after ESBWR training, test participants will exhibit an acceptably stable level of performance across trials. Accordingly, the staff finds the V&V Plan's treatment of the criterion for stable participant performance acceptable.

18.11.3.1.3.6.5 Pilot Testing

- (1) A pilot study should be conducted prior to conducting the integrated validation tests to provide an opportunity to assess the adequacy of the test design, performance measures, and data collection methods.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 5.4.6, addresses pilot studies. A pilot test will be conducted before the actual validation trials. The pilot test will use essentially the same methods as the tests themselves. Accordingly, the staff finds the V&V Plan's treatment of the criterion for conducting pilot tests before validation acceptable.

- (2) If possible, participants who will operate the integrated system in the validation tests should not be used in the pilot study. If the pilot study must be conducted using the validation test participants, then:
 - The scenarios used for the pilot study should be different from those used in the validation tests, and
 - Care should be given to provide reasonable assurance that the participants do not become so familiar with the data collection process that it may result in response bias.

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Section 5.4.6, addresses pilot studies. Section 5.4.6 states that participants in the pilot test will differ from participants in the validation tests. If a participant must be used in both tests, scenarios will be different. Accordingly, the staff finds the V&V Plan's treatment of the criterion for participant selection acceptable.

18.11.3.1.3.7 Data Analysis and Interpretation

The staff identified that NEDO-33276, Revision 1, did not address the five criteria below for the data analysis and interpretation review topic and Criterion (2) for the validation conclusions review topic to support an implementation level of review. In RAI 18.11-29 and its supplements, the staff requested that the applicant describe the methodology used for data analysis and interpretation, including (1) what methods will be used to analyze data and to assess performance criteria, (2) how HEDs will be identified, (3) how consistency across different measures will be evaluated, and (4) how data analysis will be verified for correctness. RAI 18.11-29 was being tracked as an open item in the SER with open items. In its responses, the applicant revised NEDO-33276 to address each of these topics. As described below, the staff finds that the applicant provided information sufficient to address the NUREG-0711 review

criteria for data analysis and interpretation and validation conclusions and to support an IP level of review. The staff confirmed that NEDE-33276P, Revision 3, included the proposed changes. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-29 is resolved.

- (1) Validation test data should be analyzed through a combination of quantitative and qualitative methods. The relationship between observed performance data and the established performance criteria should be clearly established and justified based upon the analyses performed.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 5.4.7 addresses data analysis and interpretation. Analyses will be conducted for four levels of performance measures. These measures are described in the proprietary SER. The specific analyses will depend on the type and quality of the data. For each level, NEDE-33276P identifies the comparisons to be made between actual data collected and the performance criteria established. These comparisons will generally be made using quantitative comparisons. Qualitative assessment will also be made using observer and participant evaluations. These evaluations will address, for example, the influence of factors such as lighting and noise level.

NEDE-33276P, Revision 4, provides an acceptable methodology for data analysis. The specific analyses will be developed in accordance with Design Commitment 12 in DCD Tier 1, Revision 9, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for data analysis acceptable.

- (2) For performance measures used as pass/fail indicators, failed indicators must be resolved before the design can be validated. Where performance does not meet criteria for the other performance measures, the results should be evaluated using the HED evaluation process.

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Section 5.4.7 indicates that plant core thermal-hydraulic, plant HRA/PRA, and personnel task measures are used for pass/fail criteria. For these measures, if a failure occurs, it must be resolved before the design can be validated. For the other "supplemental" measures, HEDs are defined if a measure's criterion is not met.

In view of the above, NEDE-33276P, Revision 4 provides an acceptable methodology for the treatment of pass/fail criteria and other measures. The specific test procedures will be developed in accordance with Design Commitment 12 in DCD Tier 1, Revision 9, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for treatment of pass/fail criteria and other measures acceptable.

- (3) The degree of convergent validity should be evaluated, i.e., the convergence or consistency of the measures of performance.

Evaluation of Criterion (3)

NEDE-33276P, Revision 4, Section 5.4.7, indicates that convergent validity will be assessed by comparing the results of performance measures that measure the same or closely related

aspects of performance. An HED will be created where measures that are expected to converge do not do so. The staff finds this approach acceptable because it ensures data consistency across similar performance measures.

NEDE-33276P, Revision 4, provides an acceptable methodology for development of measures for the treatment of convergent validity. The specific measures used in convergent validation will be developed in accordance with Design Commitment 12 in DCD Tier 1, Revision 9, Section 3.3, Table 3.3-2, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for convergent validity acceptable.

- (4) The data analyses should be independently verified for correctness of analysis.

Evaluation of Criterion (4)

NEDE-33276P, Revision 4, Section 5.4.7 indicates that data analyses and conclusions will be independently verified. Accordingly, the staff finds the V&V Plan's treatment of the criterion for analysis verification acceptable.

- (5) The inference from observed performance to estimated real-world performance should allow for margin of error; i.e., some allowance should be made to reflect the fact that actual performance may be slightly more variable than observed validation test performance.

Evaluation of Criterion (5)

NEDE-33276P, Revision 4, Section 5.4.7, indicates that when making inferences from observed performance to estimated real-world performance, an allowance for margin of error will be made. The staff concludes that the V&V IP conforms to the NUREG criterion. The direction is general but sufficient because the applicant's use of a full scope simulator for integrated system validation will minimize differences between testing and real-world performance. Where inferences are needed, specific error margins will be developed in accordance with DCD Tier 1, Revision 9, Section 3.3, Table 3.3-2, Design Commitment 12, which is discussed in Section 18.11.3 of this report. Accordingly, the staff finds the V&V Plan's treatment of the criterion for error margins acceptable.

18.11.3.1.3.8 Validation Conclusions

- (1) The statistical and logical bases for determining that performance of the integrated system is and will be acceptable should be clearly documented.

Evaluation of Criterion (1)

NEDE-33276P, Revision 4, Section 5.5, addresses the documentation of results and indicates that the results report documents the validation conclusions and their bases. Accordingly, the staff finds the V&V Plan's treatment of the criterion for validation conclusions acceptable.

- (2) Validation limitations should be considered in terms of identifying their possible effects on validation conclusions and impact on design implementation. These include:
 - Aspects of the tests that were not well controlled

- Potential differences between the test situation and actual operations, such as absence of productivity-safety conflicts
- Potential differences between the validated design and plant as built (if validation is directed to an actual plant under construction where such information is available or a new design using validation results of a predecessor).

Evaluation of Criterion (2)

NEDE-33276P, Revision 4, Section 5.5, indicates that the limitations of validation testing will be addressed and will include considerations noted in the staff's review criterion. In instances where validation limitations impact the conclusions, the validation process will be extended to the plant itself and will be addressed by NEDO-33278, Revision 4, "ESBWR Human Factors Engineering Design Implementation Plan." Accordingly, the staff finds the V&V Plan's treatment of the criterion for validation limitations acceptable.

18.11.3.1.4 Human Engineering Discrepancy Resolution

In RAI 18.11-32 and its supplements, the staff requested that the applicant describe the methodology for the evaluation and resolution of HEDs. RAI 18.11-32 was being tracked as an open item in the SER with open items. In its responses, the applicant revised NEDO-33276 to provide a detailed methodology for HED evaluation and resolution. As described below, the staff finds that the applicant provided sufficient information to address the NUREG-0711 review criteria for HED resolution and to support an IP level of review. The staff confirmed that the proposed changes were included in NEDE-33276P, Revision 2. Based on the applicant's responses and revision to NEDE-33276P, RAI 18.11-32 is resolved.

- (1) HED Justification—Discrepancies could be acceptable within the context of the fully integrated design. If sufficient justification exists, a deviation from the guidelines may not constitute an HED. The technical basis for such a determination could include an analysis of recent literature or current practices, tradeoff studies, or design engineering evaluations and data. Unjustified discrepancies should be identified as HEDs to be addressed by the HED resolution.

Evaluation of Criterion (1)

NEDE 33276P, Revision 4, Section 6, describes the HED identification and resolution process. Section 6.4.2 provides the methodology for HED justification. Technical bases for HED justification are identified and include the analysis of new information, current practices, tradeoff studies, and engineering evaluations. The methodology does not permit HEDs that constitute safety concerns or performance problems to be justified. Accordingly, the staff finds the V&V Plan's treatment of the criterion for HED justification acceptable.

- (2) HED Analysis—The following should be included in the HED evaluations:
 - Plant system—the potential effects of all HEDs relevant to a single plant system should be evaluated. The potential effects of these HEDs on plant safety and personnel performance should be determined, in part, by the safety significance of the plant system(s), their effect on SAR accident analyses, and their relationship to risk significant sequences in the plant PRA.
 - HED scope

- Global features HEDs—these are HEDs that relate to configurational and environmental aspects of the design such as lighting, ventilation, and traffic flow. They relate to general human performance issues.
 - Standardized features HEDs—these are HEDs that relate to design features that are governed by the applicant's design guidelines used across various controls and displays of the HSI (e.g., display screen organization and conventions for format, coding, and labeling). Because a single guideline may be used across many aspects of the design, a single HED could be applicable to many personnel tasks and plant systems.
 - Detailed features HEDs—these are HEDs that relate to design features that are not standardized, thus [their] generality has to be assessed.
 - Other—this subcategory specifically pertains to HEDs identified from integrated system validation that cannot be easily assigned to any of the three preceding categories.
- Individual HSI or procedure—HEDs should be analyzed with respect to individual HSIs and procedures. The potential effects of these HEDs on plant safety and personnel performance are determined, in part, by the safety significance of the plant system(s) that are related to the particular component.
 - Personnel function—HEDs should be analyzed with respect to individual personnel functions. The potential effects of these HEDs is determined, in part, by the importance of the personnel function to plant safety (e.g., consequences of failure) and their cumulative effect on personnel performance (e.g., degree of impairment and types of potential errors).
 - HEDs should also be analyzed with respect to the cumulative effects of multiple HEDs on plant safety and personnel performance. While an individual HED might not be considered sufficiently severe to require correction, the combined effect of several HEDs upon the single aspect of the design could have significant consequences to plant safety and, therefore, necessitate corrective action. Likewise, when a single plant system is associated with multiple HEDs that affect a number of HSI components, then their possible combined effect on the operation of that plant system should be considered.
 - In addition to addressing the specific HEDs, the analysis should treat the HEDs as indications of potentially broader problems. For example, identifying multiple HEDs associated with one particular aspect of the HSI design, such as the remote shutdown panel, could also indicate that there are other problems with that aspect of the design, such as inconsistent use of procedures and standards. In some cases, the evaluation of HEDs could warrant further review in the identified areas of concern.

Evaluation of Criterion (2)

NEDE 33276P, Revision 4, Section 6.4, describes the HED analysis and resolution methodology. The scope and impact of each HED are analyzed in the context of other open HEDs. When an HED reflects a global or standard design feature, the broader impact of the HED is assessed. This approach enables the analyst to identify crosscutting or programmatic concerns. When such concerns are found they are entered into HFEITS for resolution.

Specific information considered during analysis includes system or systems affected, whether the HED affects global, standardized, or detailed design features, the HSIs affected, the personnel functions or tasks affected, and the procedures or training affected.

The methodology also considers the cumulative impact of HED in the context of other open HEDs affecting the same design features, functions, or processes.

Accordingly, the staff finds the V&V Plan's treatment of the criterion for HED analysis acceptable.

- (3) HED Prioritization—Identification of HEDs for correction should be based upon a systematic evaluation, such as that illustrated in Figure 11.2. Priority 1 HEDs should be those with direct safety consequences and those with indirect or potential safety consequences. HEDs with significant safety consequences are those that affect personnel performance where the consequences of error could reduce the margin of plant safety below an acceptable level, as indicated by such conditions as violations of operating limits, or Technical Specification safety limits or limiting conditions for operations. They include deviations from personnel information requirements or HFE guidelines for personnel tasks that are related to plant safety. These could include the following:

- Are required by personnel tasks but are not provided by the HSI
- Do not satisfy all personnel information needs (e.g., information not presented with the proper range or precision)
- Contain deviations from HFE guidelines that are likely to lead to errors that would prevent personnel from performing the task.

HEDs with indirect safety consequences include deviations from HFE guidelines that would seriously affect the ability of personnel to perform the task. The severity of an HFE guideline deviation should be assessed in terms of the degree to which it contributes to human performance problems, such as workload and information overload.

Priority 2 HEDs should be those that do not have significant safety consequences, but do have potential consequences to plant performance/operability, non-safety-related personnel performance/efficiency, or other factors affecting overall plant operability. These include deviations from personnel information requirements and HFE guidelines for tasks associated with plant productivity, availability, and protection of investment. These HEDs should be considered for correction.

The remaining HEDs are those that do not satisfy the criteria associated with the first and second priorities. Resolution of these HEDs is not an NRC safety concern but may be resolved at the discretion of the applicant.

Evaluation of Criterion (3)

NEDE 33276P, Revision 4, Section 6.4.3, describes the HED prioritization. The HED analysis provides extensive criteria for sorting HEDs into four categories. The first category contains safety issues, the second contains plant or personnel performance issues, the third contains HFE issues without major safety or performance implications, and finally, the fourth contains the remaining items. The degree of analysis is commensurate with the degree of importance of the

issue. Accordingly, the staff finds the V&V Plan's treatment of the criterion for HED prioritization acceptable.

- (4) HED Evaluation Documentation—Each HED should be fully documented including assessment category (priority for correction), associated plant system, associated personnel function, and associated HSI or procedure. The documentation should clearly show whether the HED was dismissed or identified as needing design modification and the basis for this determination in terms of consequence to plant safety or operation should be clearly described.

Evaluation of Criterion (4)

NEDE 33276P, Revision 4, Section 6.5, describes the HED documentation. All HEDs are entered into the HFEITS database. This provides an auditable system that fully describes the HED and its resolution. It includes identifying information; any justification (if applicable); the results of the HED analysis (including systems, HSIs, personnel functions, procedures, and training that is impacted by the HED); the HED's priority and its basis; the solutions developed; the solution implementation; and the resolution effectiveness evaluation. Accordingly, the staff finds the V&V Plan's treatment of the criterion for HED documentation acceptable.

- (5) Development of Design Solutions—Design solutions to correct HEDs should be identified. The design solutions should be consistent with system and personnel requirements identified in the Preparatory Analysis (i.e., Operating Experience Review, Function and Task Analysis, and HSI Characterization).

Inter-relationships of individual HEDs should be evaluated. For example, if a single HSI component is associated with multiple HEDs, then design solutions should be considered to address these HEDs together. If a single plant system is associated with multiple HSI components that are associated with HEDs, then the design of the individual solutions should be coordinated so that their combined effect enhances rather than detracts from that system's operation.

Evaluation of Criterion (5)

NEDE 33276P, Revision 4, Section 6.4.5, addresses the development of design solutions. HEDs are analyzed to determine their cause, and solutions are developed to address them. This analysis considers the cumulative impact of other open HEDs that may be related to the affected system, HSIs, procedures, or processes. Solutions considered include design change to a system or component, software, task or reallocation, HSIs, procedure, training, and staffing/qualification. Accordingly, the staff finds the V&V Plan's treatment of the criterion for design solution development acceptable.

- (6) Design Solution Evaluation—Designs should be evaluated by repeating the appropriate analyses of the V&V. For example, the HSI Task Support Verification should be conducted to provide reasonable assurance that the design satisfies personnel task requirements. Portions of the HFE design verification analysis should be conducted to provide reasonable assurance that the design is consistent with HFE guidelines, and integrated system validation could be conducted to evaluate its usability. When the problems identified by an HED cannot be fully corrected, justification should be given.

Evaluation of Criterion (6)

NEDE-33276P, Revision 4, Section 6.4.7, addresses the evaluation of HED resolutions. All HEDs are evaluated to verify their effectiveness. Depending on the type of solution implemented, the approaches include additional verifications and validations. The portions of the V&V process that are impacted by the HED resolution are repeated. These evaluations also ensure that no new HEDs are inadvertently created by the solution. If the V&V activities do not support the finding that the resolution is effective, the HED remains open in the HFEITS and is reevaluated. HEDs are closed only after they are verified as effectively resolved. Accordingly, the staff finds the V&V Plan's treatment of the criterion for design solution evaluation acceptable.

18.11.3.2 Relationship to Other Documents

18.11.3.2.1 DCD Tier 1, Section 3.3, "Human Factors Engineering"

DCD Tier 1, Revision 9, Table 3.3-2, Item 1, contains the Tier 1 ITAAC developed by the applicant for HFE. Table 3.3-2 contains 10 items, one for each element of NUREG-0711 (except HFE program management, procedures and training), plus one item which addresses integrated system validation scenarios. Each item in Table 3.3-2 is linked to the corresponding ESBWR element IP. As described in Section 14.3.9 of this report, DCD Tier 1, Section 3.3 provides sufficient ITAAC to confirm that applicable HFE elements are completed in accordance with their respective IPs, which includes confirming that the V&V plan is completed in accordance with the IP (NEDE-33276, Revision 4), which the staff has reviewed and approved.

18.11.3.2.2 DCD Tier 2, Section 18.11, "Human Factors Verification and Validation"

In RAIs 18.11-35 and 18.11-37, the staff requested that the applicant address inconsistencies between DCD Tier 2, Section 18.11, and NEDE-33276P and clarify references to NEDE-33276P and NEDE-33217P. RAIs 18.11-35 and 18.11-37 were being tracked as open items in the SER with open items. In its responses, the applicant corrected the inconsistencies between DCD Tier 2, Section 18.11, and NEDE-33276P and corrected the references. The staff confirmed that DCD Tier 2, Section 18.11, Revision 6, included the proposed changes. Based on the applicant's responses, RAIs 18.11-35 and 18.11-37 are resolved.

DCD Tier 2, Revision 9, Section 18.11, provides a high-level description of the ESBWR V&V process. This section of the DCD also references the detailed IP (NEDE-33276, Revision 4), which is designated as Tier 2*. As discussed above, NEDE-33276P, Revision 4 describes a V&V program that addresses the NUREG-0711 criteria for V&V. Thus, Tier 2, together with the referenced IP provides an acceptable description of the ESBWR V&V program.

18.11.4 Conclusions

The staff reviewed the ESBWR HFE V&V at an IP level (see Section 18.4.1 of this report for a discussion of review levels), using the review criteria in Section 11.4 of NUREG-0711. For the reasons set forth above, the staff concludes that the ESBWR V&V Program, as described in NEDE-33276P, Revision 4, provides an acceptable methodology for the following:

- Identifying a sample of operational conditions that (1) includes conditions that are representative of the range of events that could be encountered during operation of the

plant, (2) reflects the characteristics that are expected to contribute to system performance variation, and (3) considers the safety significance of HSI components

- Developing an HSI inventory and characterization that accurately describes all HSI displays, controls, and related equipment that are within the defined scope of the HSI design review
- Verifying that the HSI provides all alarms, information, and control capabilities needed for personnel tasks
- Verifying that the characteristics of the HSI and the environment in which it is used conform to HFE guidelines
- Validating the integrated system design (i.e., hardware, software, and personnel elements) using performance-based tests to determine whether it acceptably supports safe operation of the plant
- Developing an HED evaluation process that acceptably prioritizes HEDs in terms of their need for improvement and developing design solutions and a realistic schedule for implementation to address those HEDs selected for correction

DCD Tier 1, Revision 9, Section 3.3, provides ITAAC sufficient to confirm that the V&V is completed in accordance with the IP (NEDO-33276, Revision 4), which the staff has reviewed and approved. Accordingly, the staff concludes that the applicant's V&V is acceptable at the IP level.

18.12 Design Implementation

18.12.1 Regulatory Criteria

The objective of reviewing design implementation is to verify that the applicant's as-built design conforms to the verified and validated design that resulted from the HFE design process.

To review the applicant's design implementation plan, the staff used the review criteria in NUREG-0711, Section 12.4.

18.12.2 Summary of Technical Information

DCD Tier 2, Revision 9, Section 18.12, describes the ESBWR design implementation. DCD Tier 2, Revision 9, Section 18.12, incorporates by reference NEDE-33217P, Revision 6, and NEDO-33278.

The staff also reviewed the following ESBWR documents:

- ESBWR DCD Tier 1, Revision 9, Section 3.3
- GEH responses to RAIs 18.12-1 through 18.12-7

18.12.3 Staff Evaluation

The staff performed an IP level of review as described in NUREG-0711 and Section 18.1 of this report. This section presents the applicable review criteria from NUREG-0711 (reproduced below), followed by an evaluation of each criterion. In addition, this section also addresses related documents (i.e., DCD Tier 1 and Tier 2 information).

18.12.3.1 NUREG–0711 Review Criteria

NUREG–0711 includes three criteria for this topic.

- (1) Aspects of the design that were not addressed in V&V should be evaluated using an appropriate V&V method. Aspects of the design addressed by this criterion may include design characteristics such as new or modified displays for plant-specific design features and features that cannot be evaluated in a simulator such as CR lighting and noise.

Evaluation of Criterion (1)

According to NEDO-33278, Revision 4, Section 1.1, one purpose of design implementation is to verify aspects of the design that may not have been evaluated previously in the V&V process, including any hardware, software, or new or modified displays that were absent from the simulator-based integrated V&V process, and any physical or environmental (e.g., noise, lighting) differences between those present at the V&V process and the as-built CR.

NEDO-33278, Revision 4, Section 3.3 describes the methodology, and NEDO-33278, Revision 4, Section 4.3 describes its implementation. Section 3.3 outlines a scope in accordance with the criterion that specifies the aspects of the design that are included in this verification. Accordingly, the staff finds the Design IP's treatment of aspects of the design not addressed in V&V acceptable.

- (2) The final (as-built in the plant) HSIs, procedures, and training should be compared with the detailed design description to verify that they conform to the design that resulted from the HFE design process and V&V activities. Any identified discrepancies should be corrected or justified.

Evaluation of Criterion (2)

In RAI 18.12-2, the staff requested that the applicant clarify the criteria that will be used to determine whether the plant as-built design is consistent with the HFE design that was verified and validated. RAI 18.12-2 was being tracked as an open item in the SER with open items. In response, the applicant explained that an HSI report provides the basis for acceptance criteria for as built design verification. The staff finds that the response is acceptable since the revised NEDO-33278 conforms to the NUREG–0711 guidance to verify the actual HFE design is consistent with the design that was verified and validated. The staff confirmed that NEDO-33278, Revision 3, includes the proposed changes. Based on the applicant's response, RAIs 18.12-2 is resolved.

In RAI 18.12-3 and its supplements, the staff requested that the applicant clarify the as-built design itself is verified and not just design documentation such as procurement, construction, and engineering change documentation. RAI 18.12-3 was being tracked as an open item in the SER with open items. In its responses, the applicant identified that the verification will be performed on the as-built design. The staff finds that the responses are acceptable since they conform to the NUREG–0711 guidance to verify the actual physical HFE design. The staff confirmed that NEDO-33278, Revision 3, included the proposed changes. Based on the applicant's responses, RAI 18.12-3 is resolved.

In RAI 18.12-4 and its supplements, the staff requested that the applicant clarify the responsibilities for as-built design verification between the vendor, the COL holder, and the

owners' group. The staff also requested clarification of whether as-built design verification would be performed only for the initial plant or all plants. RAI 18.12-4 was being tracked as an open item in the SER with open items. In its responses, the applicant clarified that as-built design verification is the responsibility of the COL holder and that it will be performed on each plant. The staff finds that the revised NEDO-33278 describes a design verification process that conforms to NUREG-0711. The staff confirmed that NEDO-33278, Revision 3, includes the proposed changes. Based on the applicant's responses, RAI 18.12-4 is resolved.

According to NEDO-33278, Revision 4, Section 1.1, another purpose of design implementation is to "confirm that the final HSIs, procedures and training (as-built) HFE design conforms to the ESBWR standard plant design resulting from the HFE design process and V&V activities." It also states, "Any identified discrepancies are assessed and properly addressed." Two sections provide the methodology for doing so—Section 3.1 addresses verification of the as-built HSIs, and Section 3.2 addresses the verification of the as-built procedures and training. Sections 4.1 and 4.2 describe the implementation of these methodologies.

With respect to verification of the as-built HSIs, DCD Tier 2, Revision 9, Section 18.12.2.1, states that the HSIs and their design characteristics are established in the HSI design activity, and they are subsequently evaluated and confirmed in the HFE V&V. Following the HFE V&V, the HSIs and their design characteristics are revised and become part of the plant's design basis and also become the acceptance criteria for the verification of the equipment in the as-built installation.

NEDO-33278, Revision 4, Section 3.1.3, states that the final as-built HSIs and their design characteristics are compared with the HSIs in the detailed standard plant design to verify that they conform to the design that resulted from the HFE design process and V&V activities. Section 3.1.4 states that this verification of the as-built HSIs will be accomplished by performing a physical as-built verification of the MCR, panels and HSIs, and ascertaining that the HSI screens are the same file and revision as used for the HFE V&V. Section 4.1.2.3 states that this as-built verification will ensure that any critical dimensions or physical attributes that may affect the operators' interaction with the HSI are the same as those tested in the HFE V&V, and that a review of the HSI screen files will verify that the file name and revision are the same as was used for the HFE V&V. Section 3.1.4(2) states that an HED is written to resolve the following types of issues: if an as-built verification indicates a variance from the HSI design specifications; or if there is insufficient documentation to confirm that the as-built HSI software is the same as that verified in the HFE V&V.

With respect to verification of as-built procedures and training, DCD Tier 2, Revision 9, Section 18.12.2.2, states that the approach is to conduct an audit of the as-built plant procedures and training.

NEDO-33278, Revision 4, Section 3.2.2, states that the goal of the audit of the standard as-built plant procedures and training is to compare the as-built documents to the corresponding documents used in the HFE V&V and assess any differences. Section 3.2.3 states that the final as-built procedures and training are compared with the standard plant procedures and documentation to verify that they conform to the design that resulted from the HFE design process and V&V activities. Section 3.2.4 states that an HED is written to resolve any deviations or changes.

Accordingly, the staff finds the Design IP's treatment of the final as-built comparison acceptable.

- (3) All HFE-related issues documented in the issue tracking system should be verified as adequately addressed.

Evaluation of Criterion (3)

NEDO-33278, Revision 4, Section 1.1, indicates that one purpose of design implementation is to “verify resolution of remaining Human Engineering Discrepancies (HEDs) and open items from the Human Factors Engineering Issue Tracking System (HFEITS).” Section 3.4 describes the methodology for doing so. Section 3.4.1 states that the HFE V&V of the standard plant design addresses the bulk of the HEDs from the HFE design and development. Following acceptance of the standard plant design, the responsibility for HFEITS is transferred to the fleetwide owners’ group. During and after design implementation, for each plant built based on the standard plant design, issues and HEDs continue to be identified and resolved in the HFEITS under the responsibility of the COL holder with support from the fleetwide owners’ group. Section 3.4.2 states that a goal of the design implementation is to evaluate the remaining HEDs and open issues in HFEITS for the ESBWR standard plant design for their impact on the safe operation of the plant.

Accordingly, the staff finds the Design IP’s treatment of verification of the issue tracking system acceptable.

18.12.3.2 Relationship to Other Documents

18.12.3.2.1 DCD Tier 1, Section 3.3, “Human Factors Engineering”

DCD Tier 1, Revision 9, Table 3.3-2, contains the Tier 1 ITAAC developed by the applicant for HFE. Table 3.3-2 contains 10 items, one for each element of NUREG–0711 (except HFE program management, procedures and training), plus one item which addresses integrated system validation scenarios. Each item in Table 3.3-2 is linked to the corresponding ESBWR element IP. As described in Section 14.3.9 of this report, DCD Tier 1, Section 3.3, provides ITAAC sufficient to confirm that applicable HFE elements are completed in accordance with their respective IPs, which includes confirming that the design implementation is completed in accordance with the IP (NEDO-33278, Revision 4), which the staff has reviewed and approved.

18.12.3.2.2 DCD Tier 2, Section 18.12, “Design Implementation”

In RAI 18.12-7, the staff requested that the applicant address inconsistencies between DCD Tier 2, Revision 3, Section 18.12, and NEDO-33278, Revision 2. RAI 18.12-7 was being tracked as an open item in the SER with open items. In response, the applicant proposed changes to DCD Tier 2 to be consistent with NEDO-33278. The staff confirmed that DCD Tier 2, Revision 5, Section 18.12, which included additional modifications beyond the RAI response, was consistent with NEDO-33278, Revision 3. Based on the applicant’s response and the DCD revision, RAI 18.12-7 is resolved.

DCD Tier 2, Revision 9, Section 18.12, provides a high-level description of the ESBWR design implementation activities, including the objectives and scope, and the key elements of the design implementation methodology. This section of the DCD also references the detailed IP (NEDO-33278, Revision 4), which is designated as Tier 2*. As discussed above, NEDO-33278, Revision 4 describes a design implementation program that addresses the NUREG–0711 criteria for design implementation. Thus, Tier 2, together with the referenced IP provides an acceptable description of the ESBWR design implementation program.

18.12.4 Conclusions

The staff reviewed the ESBWR design implementation at an IP level (see Section 18.1.4 of this report for a discussion of review levels), using the review criteria in Section 12.4 of NUREG-0711. For the reasons set forth above, the staff concludes that the ESBWR design implementation program, as described in NEDO-33278, Revision 4, provides an acceptable methodology to ensure that the as-built design conforms to the verified and validated design that resulted from the HFE design process. DCD Tier 1, Revision 9, Section 3.3, provides ITAAC sufficient to confirm that the design implementation is completed in accordance with the IP (NEDO-33278, Revision 4), which the staff has reviewed and approved. Accordingly, the staff concludes that the applicant's design implementation is acceptable at the IP level.

18.13 Human Performance Monitoring

18.13.1 Regulatory Criteria

The objective of reviewing human performance monitoring is to verify that the applicant has prepared a human performance monitoring strategy for ensuring that no significant safety degradation occurs because of any changes that are made in the plant and to provide adequate assurance that the conclusions that have been drawn from the evaluation remain valid over time. The applicant may incorporate this monitoring strategy into its problem identification and corrective action program.

To review the applicant's human performance monitoring (HPM) plan, the staff used the review criteria in NUREG-0711, Section 13.4.

18.13.2 Summary of Technical Information

The ESBWR HPM is described in DCD Tier 2, Revision 9, Section 18.13. DCD Tier 2, Revision 9, Section 18.13, incorporates by reference NEDE-33217P, Revision 6, and NEDO-33277, Revision 4, "ESBWR Human Factors Engineering Human Performance Monitoring Implementation Plan."

The staff also reviewed the following ESBWR documents:

- ESBWR DCD Tier 1, Revision 9, Section 3.3
- NEDE-33276P
- GEH response to RAIs 18.13-1 through 18.13-5

18.13.3 Staff Evaluation

The staff performed an IP level of review as described in NUREG-0711 and Section 18.1 of this report. This section presents the applicable review criteria from NUREG-0711 (reproduced below) followed by an evaluation of each criterion. In addition, this section also addresses related documents (i.e., DCD Tier 1 and Tier 2 information).

18.13.3.1 NUREG-0711 Review Criteria

NUREG-0711 includes five criteria for this topic.

- (1) The scope of the performance monitoring strategy should provide reasonable assurance that:
- The design can be effectively used by personnel, including within the control room and between the control room and local control stations and support centers.
 - Changes made to the HSIs, procedures, and training do not have adverse effects on personnel performance, e.g., a change interferes with previously trained skills.
 - HA can be accomplished within time and performance criteria.
 - The acceptable level of performance established during the integrated system validation is maintained.

Evaluation of Criterion (1)

The first bullet of Criterion (1) for the HPM element in NUREG-0711 states that the performance monitoring strategy should provide reasonable assurance that personnel can effectively use the design, including within the control room and between the CR and LCSs and emergency planning support centers. DCD Tier 2, Revision 9, Section 18.13, addresses this item at a high level. NEDO-33277, Revision 4, Section 1.2, "Scope," addresses it more specifically, noting the various locations for personnel actions.

DCD Tier 2, Revision 9, Section 18.13, states that the HPM program provides reasonable assurance of the following:

- The HSI design is effective during a variety of conditions ranging from normal operations through design basis accidents and key PRA scenarios.
- Changes made to the initial HSIs, procedures, and training do not have adverse effects on personnel performance.
- Acceptable performance levels established during the integrated HSI validation are maintained, using evaluation and trending methods established by the Institute of Nuclear Power Operations as part of the Human Performance Enhancement System.

NEDO-33277, Revision 4, Section 3, references the V&V portion of the design phase and describes how that provides the baseline showing the effective use of the various HSIs by personnel. Section 3.2 states that the operational phase of the HPM program provides reasonable assurance of the following:

- The acceptable level of performance established during the integrated V&V is maintained.
- Changes made to the standard ESBWR HSIs, procedures, staffing, and training are evaluated for design impact and consistently applied at all ESBWRs in a timely manner.
- Changes made to the HSI are tested in the full-scope simulator before implementation in the plant.

NEDO-33277, Revision 4, Section 3.2.4, states that periodic evaluation and trending of operators' performance of tasks with respect to time and accuracy goals are undertaken to demonstrate performance consistent with that developed during the various analyses that support the design.

In view of the foregoing, the staff finds the HPM Plan's treatment of the criterion for scope acceptable.

- (2) A human performance monitoring strategy should be developed and documented. The strategy should be capable of trending human performance after the changes have been implemented to demonstrate that performance is consistent with that assumed in the various analyses that were conducted to justify the change. Applicants may integrate, or coordinate, their performance monitoring for risk-informed changes with existing programs for monitoring personnel performance, such as the licensed operator training program and the corrective action program. If a plant change [warrants] monitoring of actions that are not included in existing training programs, it may be advantageous to adjust the existing training program rather than to develop additional monitoring programs for risk-informed purposes.

Evaluation of Criterion (2)

NEDO-33277, Revision 4, and DCD Tier 2, Revision 9, Section 18.13, provide the overview of a detailed plan for HPM during the design, V&V, and operational phases of the ESBWR. The plan includes activities for the nuclear steam supply system designer (GEH), the fleetwide ESBWR owners' group, and the COL holder (Licensee). The strategy includes well-coordinated activities. The HPM Plan outlines the use of various existing programs in the overall scheme, including the HFE V&V, the startup testing program, the CAP, the Maintenance Rule program, PRA and HRA activities, inservice inspection and inservice testing programs, the operator training program, the HFEITS, and the operating experience program. The HPM strategy is also structured to ensure standardization across the fleet of ESBWRs. Accordingly, the staff finds the HPM Plan treatment of the criterion for strategy development acceptable.

- (3) The program should be structured such that
- HAs are monitored commensurate with their safety importance.
 - Feedback of information and corrective actions are accomplished in a timely manner.
 - Degradation in performance can be detected and corrected before plant safety is compromised (e.g., by use of the plant simulator during periodic training exercises).

Evaluation of Criterion (3)

NEDO-33277, Revision 4, states that the objective of the ESBWR HPM Plan is to ensure that no safety degradation occurs because of changes in design, procedures, training, or staffing. Section 3.1.1 states that HAs are monitored commensurate with risk importance. The report also discusses risk screening of operational events for importance in Sections 1.2.2, 1.2.3, and 3.2.4. Section 3.2.4 mentions precursor and PRA analyses that are used for prioritization. Section 3.2.4 and Chapter 4 discuss the use of the full-scope simulator. The HPM Plan also discusses the use of trending and root cause analysis to understand the impact of an issue on plant operation and safety. NEDO-33277, Revision 4, Figure 2, outlines the overall structure of the program. The HPM program includes data collection, screening for importance, analyzing events to determine the cause and to trend the events, and developing corrective actions. Together, these actions should provide for a robust program that detects and corrects issues before plant safety is compromised. In this regard, Section 1.2 of the plan outlines the responsibilities of GEH, the fleetwide ESBWR owners' group, and ESBWR licensees.

Accordingly, the staff finds the HPM Plan's treatment of the criterion for the structure of the HPM strategy acceptable.

- (4) Plan of personnel performance under actual design conditions may not be readily measurable. When actual conditions cannot be simulated, monitored, or measured, the available information that most closely approximates performance data in actual conditions should be used.

Evaluation of Criterion (4)

The HPM program provides for the use of a combination of operating experience data, an ESBWR full-scope simulator, data analysis, and the involvement of the ESBWR vendor, the licensee, and the fleetwide ESBWR owners' group. This combination should provide for data and experience that are as close to actual demand conditions as is reasonably achievable. NEDO-33277, Revision 4, Chapter 3 lists the portions of the program that show its breadth. Accordingly, the staff finds the HPM Plan's treatment of the criterion for approximating performance data acceptable.

- (5) As part of the monitoring program, it is important that provisions for specific cause determination, trending of performance degradation and failures, and corrective actions be included. The cause determination should identify the cause of the failure or degraded performance to the extent that corrective action can be identified that would preclude [recurrence of] the problem or provide adequate assurance that it is anticipated prior to becoming a safety concern. The program should address failure significance, the circumstances surrounding the failure or degraded performance, the characteristics of the failure, and whether the failure is isolated or has generic or common cause implications. The monitoring program should identify and establish any corrective actions necessary to preclude the recurrence of unacceptable failures or degraded performance.

Evaluation of Criterion (5)

Using an ESBWR licensee's CAP, the HPM program has a built-in method for identifying causes of human performance issues or degradations and correcting identified issues. Industry CAPs also include trending features, and NEDO-33277, Revision 4, Section 3.2.3, notes that the licensee's CAP provides for the evaluation of conditions and trends for their potential to impact the standard ESBWR design. NEDO-33277, Revision 4, Section 3.2, states that the program addresses the significance of the failure through application of precursor analysis and HRA /PRA importance measures. The fleetwide ESBWR owners' group will be able to address the generic aspects of failures. CAPs also have features to address significant failures and to prevent the recurrence of such failures. Accordingly, the staff finds the HPM Plan's treatment of the criterion for cause determination acceptable.

18.13.3.2 Relationship to Other Documents

18.13.3.2.1 DCD Tier 1, Section 3.3, "Human Factors Engineering"

DCD Tier 1, Revision 9, Table 3.3-2, contains the Tier 1 ITAAC developed by the applicant for HFE. Table 3.3-2 contains 10 items, one for each element of NUREG-0711 (except HFE program management, procedures and training), plus one item that addresses integrated system validation scenarios. Each item in Table 3.3-2 is linked to the corresponding ESBWR element IP. As described in Section 14.3.9 of this report, DCD Tier 1, Section 3.3, provides

ITAAC sufficient to confirm that applicable HFE elements are completed in accordance with their respective IPs, which includes confirming that the HPM is completed in accordance with the IP (NEDO-33277, Revision 4), which the staff has reviewed and approved.

18.13.3.2.2 DCD Tier 2, Section 18.13, “Human Performance Monitoring”

DCD Tier 2, Revision 9, Section 18.13 provides a high-level description of the ESBWR HPM implementation activities, including the purpose, the strategy, and the key elements of the HPM process. This section of the DCD also references the detailed IP (NEDO-33277, Revision 4), which is designated as Tier 2*. As discussed above, NEDO-33277, Revision 4, describes an HPM program, which addresses the NUREG–0711 criteria for HPM. Thus, Tier 2, together with the referenced IP, provides an acceptable description of the ESBWR HPM program.

18.13.4 Conclusions

The staff reviewed the ESBWR HPM at an IP level (see Section 18.1.4 of this report for a discussion of review levels) using the review criteria in Section 13.4 of NUREG–0711. For the reasons set forth above, the staff concludes that the ESBWR HPM program, as described in NEDO-33277, Revision 4, provides an acceptable methodology for developing a monitoring strategy that ensures no significant safety degradation occurs because of plant changes. DCD Tier 1, Revision 9, Section 3.3, provides ITAAC sufficient to confirm that the HPM is completed in accordance with the IP (NEDO-33277, Revision 4), which the staff has reviewed and approved. Accordingly, the staff concludes that the applicant’s HPM is acceptable at the IP level.

18.14 Minimum Inventory

18.14.1 Regulatory Criteria

The staff reviewed the Minimum Inventory in accordance with SRP Section 14.3.9, issued March 2007. The Minimum Inventory is acceptable if it meets the guidelines of the agency’s policy prescribed in SECY-92-053. The staff evaluates the Minimum Inventory using the direction provided in SRP Section 14.3.9, with recognition that the NUREG–0711 process, as implemented by DCD Tier 2, Revision 9, Chapter 18, will validate and continue to develop the design characteristics associated with the parameters that constitute the Minimum Inventory. For clarity, in this section “Minimum Inventory” is capitalized when referring to the inventory of CDAs specifically covered by SECY-92-053 and SRP Section 14.3.9.

18.14.2 Summary of Technical Information

DCD Tier 1, Revision 9, Section 3.3, and DCD Tier 2, Revision 9, Section 18.1 list the ESBWR Minimum Inventory. DCD Tier 2, Revision 9, Section 18.5A, incorporates a process description.

The staff also reviewed the following ESBWR documents:

- RAI 18.8-47 S02, RAI 18.8-47 SO3, RAIs 18.5-35 to 18.5-40, RAI 18.5-33, RAI 18.5-34, RAI 18.7-7 SO5, RAI 18.4-41, RAI 18.7-16, RAI 18.5-41 S01
- “ESBWR Design Comparison to BWROG EPG/SAG [Boiling Water Reactor Owner’s Group Emergency Procedure Guidelines/Severe Accident Guidelines] Revision 2 for Minimum Inventory Development,” Revision 1 (ESBWR delta document)

- NEDE-33221P, Revision 4,
- NEDO-33267, Revision 4,
- NEDO-33201, Revision 5, Chapter 17, “Results Summary”

18.14.3 Staff Evaluation

In RAI 18.8-47, the staff requested that the applicant explain how Minimum Inventory is identified and state the criteria used in the selection process. As documented through several supplemental RAIs, the staff determined that the Minimum Inventory and the process to develop it should be included in the DCD. RAI 18.8-47 was being tracked as an open item in the SER with open items. In response to RAI 18.8-27 and related RAIs, the applicant revised DCD Tier 2, Revision 6, Section 18.5.1, to describe the process used to determine Minimum Inventory and included the Minimum Inventory in DCD Tier 2, Revision 6, Tables 18.1-1a and 18.1-1b. The staff evaluation of Minimum Inventory and its development described below and the staff finds them acceptable. Based on the applicant’s response and the DCD Revisions, RAI 18.8-47 is resolved.

SRP Section 14.3.9, Criterion (6), states:

Minimum Inventory of Displays, Alarms and Controls:

Tier 1 includes a Minimum Inventory of displays, controls, and alarms that are necessary to carry out the vendor’s emergency procedure guidelines (i.e., Owners’ Groups Generic Technical Guidelines) and critical actions identified from the applicant’s PRA and task analysis of operator actions. The reviewer’s evaluation of the Minimum Inventory will encompass a multi-disciplinary effort consisting of human factors, I&C, PRA, and plant, reactor, and electrical system engineering. The Minimum Inventory list has been implemented through the rule-making process for four certified designs (10 CFR Part 52 Appendixes A, B, C, and D). The criteria used to determine acceptability of the inventory includes assuring that:

- (1) The scope of these items in the Generic Technical Guidelines and PRA effort are adequately considered.
- (2) The task analysis is detailed and comprehensive.
- (3) RG 1.97, Revision 3, Category 1 variables or RG 1.97, Revision 4, Type A, B, and C variables for accident monitoring are included.
- (4) Important system displays and controls described in Tier 1 system design descriptions necessary for transient mitigation are included.

The staff has evaluated the four criteria as described below:

Criterion (1)—The scope of these items in the Generic Technical Guidelines and PRA effort is adequately considered.

Evaluation of Criterion (1)

In DCD Tier 2, Revision 9, Section 18.5.1.2, the applicant states that the BWROG EPGs are used to develop the Minimum Inventory. The applicant explains that these more generic guidelines are used because the detailed plant design needed to draft an ESBWR-specific EPG is not complete. A functional analysis of the ESBWR design was completed to link the strategy and task guidance contained in the BWROG document with the design specifics and system capabilities of the ESBWR.

The function and task elements identified in the functional analysis (for both design similarities and differences) were documented in the “ESBWR delta document” and subsequently used as input to a task analysis that identified CDAs needed to meet plant design goals and safety analysis assumptions. This subset of CDAs makes up the Minimum Inventory. Within the context of the Minimum Inventory process, the ESBWR delta document was characterized as an analytical tool used for the derivation of the ESBWR Minimum Inventory. It was not used to document the task analysis results on a step-by-step basis. This limits the staff’s ability to audit the process but is consistent with the level of detail accepted for documenting Minimum Inventory in other design centers.

The staff considers the applicant’s use of the BWROG EPGs as a starting point to be an alternate method to the guidance provided in the SRP. While the BWROG EPGs are a complete set of guidelines for the design-basis accidents applicable to the ESBWR, they are generic rather than ESBWR-specific EPGs. However, the BWROG EPGs are the basis for operating BWR EOPs, and as such they incorporate substantial design and operating experience. Because the BWROG EPGs reflect this operating experience, the staff finds them to be an acceptable starting point for the Minimum Inventory analysis when paired with an ESBWR delta document that identifies the ESBWR design similarities and differences. The staff also noted that the tasks associated with Minimum Inventory would be subject to additional detailed reviews during the task analysis described in DCD Tier 2, Revision 9, Section 18.5.2. This task analysis is part of the detailed HFE design process that implements NUREG-0711 guidance.

In DCD Tier 2, Revision 9, Section 18.5.1.2, the applicant describes how HAs identified in DCD Tier 2, Revision 9, Chapter 19, were selected for the evaluation supporting identification of the Minimum Inventory. In summary, operator actions that would contribute greater than or equal to 10 percent of the NRC safety goals (i.e., CDF 1×10^{-4} /year, LRF 1×10^{-6} /year), if not completed successfully, were identified from the larger set of risk important HAs. Four operator actions met these criteria. A task analysis of each action was subsequently completed to identify the Minimum Inventory. While only the highest risk HAs are analyzed for their potential impact on the Minimum Inventory list, NEDO-33201 identifies approximately 40 risk-important HAs identified in Chapter 17, Table 17.1-3 of the NEDO. These actions are all evaluated within the scope of the detailed task analysis described in DCD Tier 2, Revision 9, Section 18.5.2.

In view of the above, the staff determined that appropriate risk-important HAs from the ESBWR PRA were identified for inclusion in the Minimum Inventory analysis.

Criterion (2)—The task analysis is detailed and comprehensive.

Evaluation of Criterion (2)

The applicant's process uses a functional analysis of the ESBWR design to link the ESBWR operating and accident mitigation strategies identified in the BWROG EPG and ESBWR PRA with the specific design and system capabilities of the ESBWR. A task analysis of each of the resulting elements was then completed to determine the CDAs needed to meet ESBWR plant design goals and safety analysis assumptions. Different combinations of CDAs were identified depending upon whether the analyzed element's emphasis was on alerting, monitoring, diagnosing, and/or operating equipment.

The staff reviewed the completed ESBWR delta document. The staff finds that the document contains sufficient depth to ensure that design similarities and differences are properly identified and that it is an acceptable analytical tool for supporting the determination of the Minimum Inventory. The staff also reviewed the Minimum Inventory list that resulted from the task analysis. Because the staff could not draw a direct correlation between each step in the delta document and the Minimum Inventory list, the following concerns warranted additional clarification from the applicant:

- The delta document identifies several design differences that appeared to warrant additional CDAs for systems such as fuel and auxiliary pool cooling system (FAPCS), condensate and feedwater system, and control rod drive system. Several RAI open items were associated with these differences. They have all been satisfactorily addressed by the applicant as described below.

In RAI 18.5-37, the staff requested that the applicant clarify why additional controls and displays for the FAPCS were not included on the Minimum Inventory list. In response, the applicant stated that the suppression pool cooling function of the FAPCS initiates automatically and does not credit additional operator alarms or tools for manual initiation (controls and indications). The operator verifies successful initiation using the suppression pool temperature response, and additional indications, controls, and alarms are not credited. The staff finds that this position conformed to regulatory guidance contained in the Standard Review Plan Section 14.3.9. Additional details are provided below. Based on the applicant's response, RAI 18.5-37 is resolved.

In RAI 18.5-38, the staff requested that the applicant clarify why additional alarms for some analog signals of 4–20 milliamperes, such as containment water level, wetwell pressure, containment radiation, gravity-driven cooling pool level, and standby liquid control (SLC) accumulator level are not included on the Minimum Inventory list. In response, the applicant provided the following information:

Containment Water Level—The BWROG EPG does not describe any operator action that applies to the ESBWR design and relies on a specific setpoint for containment water level. A display is provided as a tool for determining correct system performance.

Wetwell Pressure—Wetwell pressure is tied directly to drywell pressure. The BWROG EPG does not describe any operator action that applies to the ESBWR design and relies on a specific setpoint for wetwell pressure. A display is provided as a tool for determining correct system performance.

Containment Radiation—The BWROG EPG does not describe any operator action that applies to the ESBWR design and relies on a specific setpoint for containment radiation

level. This action is employed in the performance of the severe accident management guidelines; however, severe accident management is not included in the minimum inventory scope.

Gravity-Driven Cooling Pool Level—The BWROG EPG does not describe any operator action that applies to the ESBWR design and relies on a specific setpoint for gravity driven cooling pool level. The operator verifies successful initiation of the gravity-driven cooling system using reactor vessel level indication. A display is provided as a tool for determining correct system performance.

SLC Accumulator Level—The BWROG EPG does not describe any operator action that applies to the ESBWR design and relies on a specific setpoint for SLC accumulator level. The operator verifies successful accumulator isolation on low level using reactor power, pressure, and level indications

The staff finds this response acceptable because there were no operator actions based on the specific parameter setpoints. This position conforms to regulatory guidance contained in SRP Section 14.3.9. Based on the applicant's response, RAI 18.5-38 is resolved.

In the RAI responses, the applicant provided additional information on how it performed the minimum inventory analysis. In summary, during the task analysis phase, plant analysts selected "primary mitigating function(s)" for steps that contained multiple options. Typically, the primary function is the automatic protective action for the ESBWR design. Manual actions are included as alternate actions. The staff finds that using primary versus alternate actions from the EOPs is consistent with the objective of Minimum Inventory in that it identifies the minimum CDAs needed to safely shut down the reactor. While not evaluated as part of the Minimum Inventory, the applicant will evaluate alternate actions as part of the detailed design task analysis described in DCD Tier 2, Revision 9, Section 18.5.2. Other steps in the BWROG EPGs identify operator actions to monitor the effectiveness of automatic system performance. Also, in the task analysis, plant analysts evaluated each HA within the context of the task sequence involving that action. The applicant compiled the Minimum Inventory for the following functions:

- HSIs needed to support decision making
- HSIs needed to support plant manipulations
- HSIs needed to prompt action
- HSIs needed to support the monitoring of task success criteria

The staff concludes that this strategy is acceptable for development of the Minimum Inventory because the proposed process provides reasonable assurance that all Minimum Inventory controls, alarms and displays are identified.

The isolation condenser system with alarm, display, and control functions is included in the Minimum Inventory Tier 1 table for RSS, but it is not included in the Minimum Inventory Tier 1 table for the CR which instead lists isolation condenser valves with display and control functions. The applicant explained that manual control from the remote shutdown panel is assumed for the isolation condenser system, and therefore, alarms, controls, and displays are included in the RSS Minimum Inventory. Automatic operation is monitored from the control room. Valve position indication and control functions are provided to ensure that system automatic functions are completed. The staff concludes that this is an acceptable position as it reflects design differences between the CR and the RSS.

Similarly, there was no documentation of the task analysis results specific to each of the risk-important HAs evaluated. The following are the four pertinent HAs from NEDO-33201, Table 17.1-3:

- The operator fails to recognize the need for low pressure makeup after depressurization.
- The operator closes the lower drywell hatch.
- The operator fails to recognize the need to makeup ICS/PCCS pool level.
- The operator fails to actuate U43 in low-pressure coolant injection (LPCI) mode.

The staff was able to correlate actions 1 and 3 to appropriate controls, alarms, and displays contained in the Minimum Inventory list. In RAI 18.5-41, the staff requested the applicant to explain how actions 2 and 4 were dispositioned. In response, the applicant provided the following information.

- Action 2: No CDAs (for example, hatch closure indication) are included in the Minimum Inventory list for this risk-important HA. The circumstance in which the action could be necessary is a plant refueling/maintenance period during which the lower drywell hatches are open. In this condition, personnel would likely be working in the drywell or its immediate vicinity, and drywell access and status would be monitored and controlled in accordance with the facility administrative procedures. Under 10 CFR 50.65(a)(4), the licensee is required to assess and manage the increased risk that may result from maintenance activities. Based on current industry practice, the administrative procedures to satisfy the requirements of 10 CFR 50.65(a)(4) would address the risk aspects of the hatch being open and would provide direction for contingency planning. In the case of a LOCA with the lower drywell hatches open, the contingency action would be to close the lower drywell hatches.
- The task of closing the lower drywell hatches in the case of a LOCA requires no additional CR CDAs. The CR CDAs needed to prompt action are a reactor water level alarm and display, which are already included in the ESBWR Minimum Inventory. The CR display needed to support decision making is a Containment Water Level display, which is also already included in the ESBWR Minimum Inventory. No CR CDAs are needed to support plant manipulations or monitoring success criteria as the task (closing the hatches) is performed locally in the reactor building.
- The staff finds that the applicant's response is acceptable since the applicant's proposed control method provides reasonable assurance that the hatch position will be effectively controlled without additional CR indication.

The applicant provided the following information on Action 4:

- Action 4: The applicant has performed additional analysis to determine whether CR indication and/or control to support actuation of the U43 LPCI mode (use of the fire protection system to provide core cooling) would substantially improve the operator's ability to ensure that this task is completed. The next paragraph summarizes the applicant's analysis.

The task of aligning the fire protection system to provide core cooling involves starting a backup LPCI pump located in the fire pump enclosure and establishing a flowpath using valves F346 and F332A or F332B (see DCD Tier 2, Figure 9.1-1). This diverse injection mode does not require offsite power or the standby diesel generators, uses the fire protection tank for a source of water, and can be operated locally. The task of aligning fire

protection for these sequences is performed in the plant locally. CR indication and/or control for system alignment would not substantially improve in the operator's ability to complete the task. The CR display and alarm that prompt the need for the task (low or lowering reactor water level) are a reactor water level alarm and display, which are included in the ESBWR Minimum Inventory. The CR display needed to determine if a task prerequisite is met (pressure below injection system limits) is a reactor pressure display, which is also included in the ESBWR Minimum Inventory. Monitoring of task success (restore reactor water level above top of active fuel) would warrant a CR display for reactor water level. As noted above, this display currently exists in the ESBWR Minimum Inventory.

Based on the assessment above, the applicant concluded that the task of aligning the Fire protection system to provide core cooling would not call for additional CR controls, displays or alarms.

The staff finds the applicant's response acceptable since the applicant's proposed control method provides reasonable assurance that alignment of the fire protection system to provide core cooling will be effectively controlled without additional CR CDAs. The applicant has appropriately supplemented PRA information with design-basis information supporting the configuration. The staff also notes that the valves that are repositioned for this alternate action are manual valves and this alternate action would not be needed until at least 72 hours after an event occurs. Use of a manually initiated alternate core cooling path provides additional diversity to the core cooling function, and the action occurs after the high workload associated with event initiation. Accordingly, RAI 18.5-41 is resolved.

With this additional information, the staff concludes that the task analysis is sufficiently rigorous to provide reasonable assurance that the applicant identified a complete Minimum Inventory. The applicant provided an adequate basis for the CDAs that were on the list, as well as those that were not. An interdisciplinary review of the inventory did not identify any inconsistencies.

Criterion (3)—Ensuring that RG 1.97, Revision 3, Category 1 variables, or RG 1.97, Revision 4, Type A, B, and C variables for accident monitoring are included.

Evaluation of Criterion (3)

The Minimum Inventory list in DCD Tier 2, Revision 9, Chapter 18.1, does not explicitly include RG 1.97 variables. While RG 1.97 variables and the CDAs relied upon to implement EPGs overlap significantly, the process proposed by the applicant does not include RG 1.97 variables as input to the Minimum Inventory. The response to RAI 18.8-47 S03 summarizes how the applicant proposed to address these variables. The applicant stated:

Regulatory Guide 1.97 focus is fundamentally different from that of SECY-92-053 in that it focuses on the execution of the detailed control room design process. The Regulatory Guide specifies accident monitoring instrument selection criteria and assigns design requirements that the detailed design process must accommodate. By contrast, the SECY-92-053 Minimum Inventory precedes the detailed design process. The two concepts significantly overlap in the area of variable selection but SECY-92-053 Minimum Inventory culminates in design certification while Regulatory Guide 1.97 & IEEE 497 guide the detailed design process and culminate in the final design.

Both the HFE and I&C chapters of the SRP address the implementation of RG 1.97 guidance. Both areas have been approved as “DAC ITAAC”, where the actual physical design is deferred because it is subject to rapidly changing technology. Consequently, if RG 1.97 variables were to be included in the Minimum Inventory process, the detailed design process would either have to be expedited (which is inconsistent with DAC ITAAC guidance) or a different, potentially less robust process, would have to be used. The staff finds that following the detailed design process, which is evaluated and approved as part of the DCD, provides a more systematic and thorough approach to the overall CR design. Accordingly, the staff finds the applicant’s plan for addressing the interface between RG 1.97 and Minimum Inventory to be acceptable.

Another supporting factor in this decision is that the applicant is committed to implementing Revision 4 of RG 1.97. RG 1.97, Revision 4, represents a significantly different approach to the topic from the previous revisions. RG 1.97, Revision 4, is based on IEEE Std. 497-2002, which establishes flexible, performance-based criteria for the selection, performance, design, qualification, display, and quality assurance of accident monitoring variables. There is no prescriptive list of accident monitoring parameters or associated functional requirements on a parameter-by-parameter basis.

Unlike previous RG 1.97 revisions, Revision 4 does not provide a specific list of parameters. Revision 4 calls for the detailed I&C design process to be completed before specific parameters are available.

The staff finds the applicant’s plan to incorporate guidance from RG 1.97 and IEEE standard 497-2002 “IEEE Standard Criteria for Accident Monitoring Instrumentation for Nuclear Power Generating Stations—Description,” in detailed design review to be an acceptable alternative to addressing the variables within Minimum Inventory. Fundamentally, the staff believes this provides a more thorough assessment of the CR HFE design, as it keeps important decisions within the framework of the detailed design processes for HFE and I&C, rather than addressing the guidance within the potentially less rigorous process used to develop Minimum Inventory. DCD Tier 1, Revision 9, Section 3.3, ITAAC 3, 6, and 9 are sufficient to confirm the RG 1.97 parameters are addressed in the HFE design. Therefore, RAI 18.8-47 S03 is resolved.

Criterion (4)—Ensuring the inclusion of important system displays and controls described in Tier 1 system design descriptions necessary for transient mitigation are included.

Evaluation of Criterion (4)

A multidisciplinary group consisting of human factors, I&C, PRA, and plant, reactor, and electrical system engineering experts reviewed the Minimum Inventory list. The staff finds that the list provides a complete list of CDAs needed to address EPGs and applicable risk-important HAs. While this design information provides definition to the CR design, the detailed design process as described in the IPs submitted as part of DCD Tier 2, Revision 9, Chapter 18 will integrate the Minimum Inventory with the complete CR design. The Minimum Inventory list provides an acceptable starting point for the CR design. The detailed HSI and CR design process implemented in satisfying the ITAAC will provide the final complete design.

18.14.4 Conclusions

The staff concludes that the ESBWR methodology used to develop the Minimum Inventory list and the resulting list conforms to the guidelines of SRP Section 14.3.9 that apply to minimum

inventory. Accordingly, the staff concludes that the ESBWR Minimum Inventory conforms to the applicable guidelines SECY-92-053.

18.15 Generic Issues Related to Human Factors Engineering

Generic issues determined to be applicable to the ESBWR design and related to HFE are evaluated below.

18.15.1 Human Factors Issues

Issue HF1.1: Shift Staffing

This issue addresses (1) ensuring that the numbers and capabilities of the staff at nuclear power plants are adequate to operate the plant so as to provide adequate protection to the public health and safety and (2) determining the minimum appropriate shift crew staffing composition. To address this issue, an applicant should consider the number and functions of the staff needed to safely perform all necessary plant operations, maintenance, and technical support for each operational mode; the minimum qualifications of plant personnel in terms of education, skill, knowledge, training, experience, and fitness for duty; and appropriate limits and conditions for shift work, including overtime, shift duration, and shift rotation.

The requirements governing this issue are set forth in 10 CFR 50.54(m), and the review criteria for this issue appear in SRP Sections 13.1.2–13.1.3, which address operating organization; SRP Section 18; NUREG–0711 element on “Staffing and Qualifications”; and RG 1.114, “Guidance to Operators at the Controls and to Senior Operators in the Control Room of a Nuclear Power Unit.” The applicant has addressed staffing at an appropriate level of detail for a design certification review in DCD Tier 1, Revision 9, Section 3.3, Design Commitment 4; DCD Tier 2, Revision 9, Section 18.6; and NEDO-33266, Revision 3. This review is addressed in Section 18.6 of this report. Therefore, Issue HF1.1 is resolved for the ESBWR design.

Section 13.1 of this report evaluates the organizational structure of the applicant as described in DCD Tier 2, Revision 9, Chapter 13.

Issue HF4.1: Inspection Procedure for Upgraded Emergency Operating Procedures

As discussed in NUREG–0933, Issue HF4.1 addresses the development of criteria by the NRC to provide assurance during inspections that operating plant EOPs are adequate and can be used effectively. The staff published lessons learned from its inspections of EOPs at plants in NUREG–1358, “Lessons Learned from the Special Inspection Program for Emergency Operating Procedures,” issued April 1989. The NRC later issued Temporary Instruction (TI) 2515/92, “Emergency Operating Procedures Team Inspections,” containing guidance for conducting these inspections. The issue is resolved for the ESBWR design with no new requirements.

DCD Tier 2, Revision 9, Sections 13 and 18.9, address procedures. DCD Tier 2, Revision 9, Section 18.9 incorporates by reference NEDO-33274. Section 13.5 of this report provides the staff’s evaluation of plant procedures, as described in DCD Tier 2, Revision 9, Sections 13.5 and 18.9. Therefore, Issue HF4.1 is resolved for the ESBWR design.

Issue HF4.4: Guidelines for Upgrading Other Procedures

As discussed in NUREG-0933, this issue addresses efforts by the staff to evaluate the quality of, and the problems associated with, existing plant procedures to ensure that plant procedures (other than EOPs, which are discussed in Issue HF4.1 above) are adequate and effective, and to guide operators in maintaining plants in a safe state under all operating conditions. The NRC is to evaluate the need to develop technical guidance for use by industry in upgrading normal and abnormal operating procedures. To satisfy the objective of this issue, an applicant should (1) develop guidelines for preparing and criteria for evaluating normal operating procedures and other procedures that affect plant safety and (2) upgrade the procedures, train the operators in their use, and implement the upgraded procedures. Note that item (2) applies only to operating plants.

The review criteria for this issue appear in SRP Sections 13.5.1 and 13.5.2, and in IN 86-64, "Deficiencies in Upgrade Programs for Plant Emergency Operating Procedures," dated August 14, 1986.

DCD Tier 2, Revision 9, Section 13.5 includes COL Information Item 13.5-4-A, which states that the COL Applicant will establish a Plant Operating Procedures Development Plan. As addressed in DCD Tier 2, Revision 9, Section 13.5.2, the plan will describe the methods and criteria for the development, V&V, implementation, maintenance, and revision of procedures that address off-normal or alarm condition operations, integrated operations, emergency operation, maintenance, modifications, radiation control, calibration, inspection, and testing. The staff concludes that the plan had appropriate scope and therefore the staff finds that COL Information Item 13.5-4-A is acceptable. Section 13.5 of this report provides the staff's evaluation of the applicant's approach to procedure development. Issue HF4.4, guidelines for upgrading other procedures, is resolved for the ESBWR design.

HF5.1: Local Control Stations

As discussed in NUREG-0933, Issue HF5.1 addresses the assurance that operator interfaces at local control stations and auxiliary operator interfaces are adequate for the safe operation and maintenance of a nuclear power plant. The concerns associated with this issue include the assurance that indications and controls available to operators at local control stations outside of the CR and remote shutdown room are sufficient and appropriate for their intended use. CR crew activities should be analyzed to establish and describe communication and control links between the CR and the auxiliary control stations. Additionally, the potential impact of the actions of auxiliary personnel on plant safety should be analyzed.

The NRC resolved this generic issue and established no new requirements. In DCD Tier 2, Revision 9, Table 1.11-1 for HF 5.1, the applicant stated that its ongoing program for the design of I&C systems and MMISs incorporates all applicable HFE requirements.

DCD Tier 1, Revision 9, Section 3.3, Design Commitment 6, and DCD Tier 2, Revision 9, Section 18.8, address HSI design. DCD Tier 2, Revision 9, Section 18.8, incorporates by reference NEDO-33268, Revision 5. Section 18.8 of this report provides the staff's review of this material. The scope of the HFE program addresses the MCR, remote shutdown panel, and the local LCSs. Therefore, Issue HF5.1 is resolved for the ESBWR design.

Issue HF5.2: Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation

As discussed in NUREG-0933, Issue HF5.2 addresses the use of advanced I&C, in particular with respect to plant annunciators. The then-existing human engineering guidelines for CRs addressed the control, display, and information concepts and technologies used in process control systems. The NRC recognized that these guidelines would not be adequate for advanced and developing technologies that could be introduced into future designs. The agency expected that improved alarm systems using advanced technologies would become available, and that the staff would develop guidelines for the use and evaluation of these longer-term alarm improvements.

This issue focused on the potential risk that could result from human error in the use of CR alarms. The staff stopped work on this issue when it integrated the development of review guidance for advanced alarms into its program to develop an advanced human-interface design review guideline. This issue was resolved with no new requirements. The NRC has subsequently issued Revision 2 of NUREG-0700, which includes HFE guidance for a variety of advanced HSIs, including advanced alarm systems.

In DCD Tier 2, Revision 9, Table 1.11-1 for HF 5.2, the applicant stated that its ongoing program for the design of I&C systems and MMISs incorporates all applicable HFE requirements. DCD Tier 1, Revision 9, Section 3.3, Design Commitment 6, and DCD Tier 2, Revision 9, Section 18.8, address HSI design. DCD Tier 2, Revision 9, Section 18.8, incorporates by reference NEDO-33268, Revision 5. Section 18.8 of this report provides the staff's review of this material. The design and the documents include an advanced alarm system and computer-based procedures. These can be acceptably reviewed using NUREG-0711 and NUREG-0700. While the design and the reviews are not complete, the process is in place, and the regulatory guidance for the review is available. Thus, Issue HF5.2 is resolved for the ESBWR design.

18.15.2 Task Action Plan Items

Item B-17: Criteria for Safety-Related Operator Actions

As discussed in NUREG-0933, Item B-17 involves the development of a time criterion for safety-related operator actions, including a determination of whether automatic actuation is necessary. Current plant designs call for the operator to act in response to certain transients. Consequently, it became necessary to develop appropriate criteria for safety-related operator actions. The criteria would include a method to determine those actions that should be automated in lieu of operator actions and development of a time criterion for safety-related operator actions. Such automation is much less necessary in the new passive plants, such as the ESBWR.

The ANSI and ANS issued ANSI/ANS 58.8-1994 to provide criteria that address this issue. NUREG-0711, Section 4, "Functional Requirements Analysis and Function Allocation," provides guidance for determining areas to be automated.

In DCD Tier 2, Revision 9, Table 1.11-1, for Item B-17, the applicant stated that the ESBWR satisfies NRC requirements concerning automation of safety-related operator actions and operator response times. The ESBWR design calls for no operator action earlier than 72 hours for any design-basis accident and has eliminated the need for operator actions for several accidents and transients.

The ESBWR plant systems are designed to provide the operator with the alarms and information needed so that plant conditions can be monitored and the performance of both passive systems and active systems can be evaluated. The nonsafety-related systems are designed to provide defense in depth for plant events, and preclude unnecessary actuation of the safety-related passive systems. Backup manual initiation exists for both the passive and active systems.

DCD Tier 1, Revision 9, Section 3.3, Design Commitment 2, and DCD Tier 2, Revision 9, Section 18.4, address functional requirements analysis and function allocation. DCD Tier 2, Revision 9, Section 18.4, incorporates by reference NEDO-33219, Revision 4, and NEDO-33220, Revision 4. Therefore, Item B-17 is resolved for the ESBWR design.

18.15.3 Three Mile Island Action Plan Issues

Issue I.D.1: Control Room Design Reviews

As discussed in NUREG-0933, TMI Issue I.D.1 addresses licensee performance of a detailed review of the CR using HFE techniques and guidelines to identify and correct design deficiencies. NUREG-0737 clarifies this issue, and NUREG-0700 provides review guidance. The staff considered this issue resolved for operating plants with completion of the detailed CR design reviews.

For new plants, the NRC addressed this issue via 10 CFR 50.34(f)(2)(iii), which requires applicants to provide, for Commission review, a CR design that reflects state-of-the-art human factors principles before committing to fabrication of CR panels and layouts. This regulation has been implemented via SRP Chapter 18 and then, by reference to NUREG-0711.

ESBWR DCD Tier 1, Revision 9, Section 3.3 and DCD Tier 2, Revision 9, Section 18, address the HFE design of the control room. DCD Tier 2, Revision 9, Section 18.2 incorporates by reference NEDE-33217P. The non-proprietary version of NEDE-33217P is designated as NEDO-33217. These were reviewed in Section 18.2 of this report. In so far as the staff has reached a determination on the information considered in Section 18.2 of this report, the applicant is employing state-of-the-art human factors principles to design the control room. As described in Section 14.3.9 of this report, DCD Tier 1, Section 3.3 provides ITAAC sufficient to confirm the completion of all HFE elements addressed in NUREG-0711 and NEDE-33217P, Revision 6, in accordance with the applicable IPs, which have been reviewed and approved by the staff. Therefore, Issue I.D.1 is resolved for the ESBWR design.

Issue I.D.2: Plant Safety Parameter Display Console

As discussed in NUREG-0933, Issue I.D.2 addresses the improvement of the presentation of information for monitoring the safety status of the plant provided to CR operators. Supplement 1 to NUREG-0737 provides guidance for improving safety function monitoring. This issue raised the need for an SPDS that clearly displays a minimum set of parameters determining the safety status of the plant. The regulation in 10 CFR 50.34(f)(2)(iv) requires a plant SPDS console to provide such a display to operators, to be capable of displaying a full range of important plant parameters and data trends on demand, and to be capable of indicating when process limits are being approached or exceeded. SRP Section 18.II.A.7 and other documents referenced therein provide regulatory guidance for implementing this requirement (including NUREG-1342).

ESBWR DCD Tier 2, Revision 9, Table 1A-1, discusses Item I.D.2 and explains how the principal functions of the SPDS are integrated into the CR design as part of the overall HFE design process. Table 1A-1 states that the ESBWR CR operator interface design incorporates the SPDS function as part of the plant status summary information that is continuously displayed on the large display panel. It will also be available on screen-based video display units. Section 18.8.3 of this report provides the staff's review of the SPDS design, which finds the design acceptable. Thus, Issue I.D.2 is resolved for the ESBWR design.

18.15.4 Generic Letters

GL 81-04: "Emergency Procedures and Training for Station Blackout Events"

GL 81-04, dated February 25, 1981, states that the staff was assessing SBO events on a generic basis (Task Action Plan Item A-44, "Station Blackout"). The GL notes that the results of the SBO study would identify the extent to which design provisions should be included to reduce the potential for or consequences of an SBO event. The unresolved safety issue has subsequently been completed and an SBO rule (10 CFR 50.63, "Loss of All Alternating Current Power") issued. Thus, this GL is encompassed by the SBO rule and related guidance documents.

As stated in DCD Tier 2, Revision 9, Appendix 1C, Table 1C-1, the ESBWR does not need emergency alternating current (ac) power to achieve safe shutdown in an SBO event. Therefore, the applicant concluded that this issue (GL 81-04) is not applicable to the ESBWR standard plant design. DCD Tier 2, Revision 9, Table 1.11-1, with regard to Task Action Plan Item A-44, makes a similar statement. Section 8.4.2.1 of this report provides the staff's review of the need for emergency ac power. The staff concludes that the safety-related passive systems are capable of withstanding a loss of all ac power for 72 hours and that the ESBWR design will be in compliance with the provisions of 10 CFR Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants," General Design Criteria 17, "Electric power systems," and 10 CFR 50.63, as they relate to the capability to achieve and maintain hot or stable shutdown in the event of an SBO. In addition, DCD Tier 2, Revision 9, Table 8.1-1, includes a note to state that procedures and training for SBO response guidelines, ac power restoration, and severe weather guidelines are developed according to Sections 13.2 and 13.5. Therefore, GL 81-04 is resolved for the ESBWR design.

GL 82-33: "Supplement 1 to NUREG-0737—Emergency Response Capabilities"

GL 82-33, dated December 17, 1982, clarifies the various post-TMI items for emergency response capabilities. Section 13 of this report addresses GL 82-33 as it relates to the TSC and EOF. Section 7.5.2 of this report addresses accident monitoring instrumentation. With respect to human factors, GL 82-33 clarifies the post-TMI items for the SPDS, detailed CR design review, upgrade of EOPs, and the functionality of emergency response facilities. Section 18.15.3, Issue I.D.2, of this report addresses human factors criteria for SPDS. Section 18.15.3, Issue I.D.1, of this report addresses the detailed CR design review. Section 18.2 of this report addresses the application of human factors principles to the EOF and TSC. Accordingly, GL 82-33, as it relates to HFE, is resolved for the ESBWR design.

GL 83-05: “Safety Evaluation of ‘Emergency Procedure Guidelines,’ Revision 2, NEDO-24934, June 1982”

GL 83-05, dated February 8, 1983, addresses the NRC review and approval of EPGs for the operating fleet of BWRs and the subsequent development of EOPs based on the EPGs. The discussion of Issue HF4.1 in Section 18.15.1 of this report addresses this area.

GL 89-06: “Task Action Plan Item I.D.2—Safety Parameter Display System—10 CFR 50.54(f)”

GL 89-06, dated April 12, 1989, addresses NRC findings related to the adequacy of SPDS installations at operating reactor facilities and forwards additional guidance in the form of NUREG-1342 for their use. Section 18.15.3, TMI Issue I.D.2, of this report fully addresses this item.

19.0 PROBABILISTIC RISK ASSESSMENT AND SEVERE ACCIDENT EVALUATION

19.0 Background

The purpose of the U.S. Nuclear Regulatory Commission (NRC) staff's review of the economic simplified boiling-water reactor (ESBWR) probabilistic risk assessment (PRA) and severe accident evaluation is to ensure that GE-Hitachi Nuclear Energy (GEH) (or the applicant) has adequately addressed the Commission's objectives. The NRC derived these objectives from Title 10 of the *Code of Federal Regulations* (10 CFR) Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants"; the Commission's Severe Reactor Accident Policy Statement regarding future designs and existing plants; the Commission's Safety Goals Policy Statement; and the Commission-approved positions concerning severe accident requirements for advanced reactors contained in SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs," dated April 2, 1993, and other documents. The objectives reflect the Commission's interest in the use of PRA in regulatory activities as indicated in the policy statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Regulatory Activities." Specifically, the Commission has stated the objectives in numerous statements and Commission guidance, including the following:

NRC Policy Statement, "Severe Reactor Accidents Regarding Future Designs and Existing Plants," Volume 50, page 32138, of the *Federal Register* (50 FR 32138), dated August 8, 1985.

NRC Policy Statement, "Safety Goals for the Operations of Nuclear Power Plants," 51 FR 28044, dated August 21, 1986.

NRC Policy Statement, "Nuclear Power Plant Standardization," 52 FR 34884, dated September 15, 1987.

NRC Policy Statement, "The Use of Probabilistic Risk Assessment Methods in Nuclear Regulatory Activities," 60 FR 42622, dated August 16, 1995.

SECY-90-016, "Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements," dated January 12, 1990, and the related staff requirements memorandum (SRM), dated June 26, 1990.

SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs," dated April 2, 1993, and the related SRM, dated July 21, 1993.

SECY-96-128, "Policy and Key Technical Issues Pertaining to the Westinghouse AP600 Standardized Passive Reactor Design," dated June 12, 1996, and the related SRM, dated January 15, 1997.

SECY-97-044, "Policy and Key Technical Issues Pertaining to the Westinghouse AP600 Standardized Passive Reactor Design," dated February 18, 1997, and the related SRM, dated June 30, 1997.

The first four NRC policy statements provide guidance regarding the appropriate way to address severe accidents and use PRA. The Commission staff requirements memoranda (SRMs) relating to SECY-90-016, SECY-93-087, SECY-96-128, and SECY-97-044 provide Commission-approved guidance for implementing features in new designs to prevent severe accidents and to mitigate their effects, should they occur.

With regard to PRA and severe accident evaluations, 10 CFR Part 52, which was in effect at the time GEH submitted the ESBWR application for design certification, required a design certification application to include PRA and severe accident information in accordance with the following NRC regulations:

- 10 CFR 52.47(a)(8), which provides information with respect to compliance with a number of the technically relevant positions of the Three Mile Island (TMI) requirements in 10 CFR 50.34(f)
- 10 CFR 52.47(a)(21), which outlines proposed technical resolutions of those unresolved safety issues and medium- and high-priority generic safety issues identified in the version of NUREG-0933, "A Prioritization of Generic Safety Issues," current within 6 months before the docket date of the application and technically relevant to the design
- 10 CFR 52.47(a)(27), which describes a design-specific PRA

19.1 Probabilistic Risk Assessment

19.1.1 Introduction

The staff's review of the PRA and severe accident evaluation comprised the following three main areas:

- (1) Design-specific PRA
- (2) Severe accident evaluations
- (3) Application of results and insights of the design-specific PRA

The purpose of the staff's review is to ensure that the applicant has adequately addressed the Commission's objectives. These objectives include the following:

- Use the PRA to do the following:
 - Identify and address potential design features and plant operational vulnerabilities; for example, vulnerabilities in which a small number of failures could lead to core damage, containment failure, or large releases (i.e., assumed individual or common-cause failures [CCFs] could drive plant risk to unacceptable levels with respect to the Commission's goals, as presented below)
 - Reduce or eliminate the significant risk contributors of existing operating plants applicable to the new design by introducing appropriate features and requirements
 - Select among alternative features, operational strategies, and design options
- Identify risk-informed safety insights based on systematic evaluations of the risk associated with the design such that the applicant can identify and describe the following:

- The design’s robustness, levels of defense-in-depth, and tolerance of severe accidents initiated by either internal or external events
- The risk significance of potential human errors associated with the design
- Determine how the risk associated with the design compares against the Commission’s goals of less than 1×10^{-4} per year (/yr) for core damage frequency (CDF) and less than 1×10^{-6} /yr for large release frequency (LRF). In addition, compare the design against the Commission’s approved use of a containment performance goal (CPG), which includes (1) a deterministic goal that containment integrity be maintained for approximately 24 hours following the onset of core damage for the more likely severe accident challenges and (2) a probabilistic goal that the conditional core damage probability be less than 0.1 for the composite of all core damage sequences assessed in the PRA.
- Assess the balance between features of the design that prevent or mitigate severe accidents.
- Determine whether the plant design represents a reduction in risk compared to existing operating plants.¹
- Demonstrate compliance with 10 CFR 50.34(f)(1)(i), which requires that a plant-specific PRA be performed to seek improvements in the reliability of core and containment heat removal (CHR) systems that are significant and practical.
- Use the PRA in support of the process employed to determine whether regulatory treatment of nonsafety systems (RTNSS) is necessary and, if appropriate, to identify the systems, structures, and components (SSCs) included in RTNSS.
- Use the PRA in support of programs associated with plant operations (e.g., technical specifications [TS], reliability assurance, human factors, and maintenance).
- Use the PRA to identify and support the development of specifications and performance objectives for the plant design, construction, inspection, and operation, such as inspections, tests, analyses, and acceptance criteria (ITAAC), reliability assurance program, TS, and combined license (COL) action items and interface requirements.

19.1.2 Quality of Probabilistic Risk Assessment

19.1.2.1 Summary of Technical Information

19.1.2.1.1 Description of the Probabilistic Risk Assessment

The ESBWR PRA is a full-scope (Levels 1, 2, and 3) PRA. The levels correspond to the modeling of the three major phases of a severe accident: initiation to core damage (Level 1), core damage to containment failure and release (Level 2), and assessment of radiological consequences (Level 3). The PRA also covers both internal and external events for at-power and shutdown operations.

¹ The reference to existing operating plants applies to the LWR plant technology that existed at the time the Commission issued its Severe Accident Policy Statement on August 8, 1985.

The ESBWR Level 1 PRA uses a linked fault tree methodology. Fault trees have been developed and evaluated for the major ESBWR frontline and support systems to determine the probability that the emergency core cooling and decay heat removal (DHR) systems perform their intended function when demanded. Transient and loss-of-coolant accident (LOCA) initiating events have been consolidated into major accident event sequences that are described by the accident event trees. These event trees are used to calculate the frequency of core damage sequences by directly linking the fault trees and solving for the minimal cutsets. Outcomes of the event trees are transferred to containment event trees (CETs) for further treatment to determine frequencies of radioactive releases to the environment.

Results of the CET analyses provide the necessary input to model and assess the transport of fission products through the drywell and containment, calculate fission product release fractions associated with containment release paths, and determine potential consequences associated with each fission product release category.

The postulated initiating events addressed in the at-power PRA are derived from a review of boiling-water reactor (BWR) nuclear power plant operating experience, as summarized in NUREG/CR-5750, "Rates of Initiating Events at U.S. Nuclear Power Plants: 1987-1995," issued February 1999. NUREG/CR-5750 builds on previous industry studies with similar objectives, such as NUREG/CR-3862, "Development of Transient Initiating Event Frequencies for Use in Probabilistic Risk Assessments," issued May 1985. The NUREG/CR-5750 categories are applicable, in general, to all BWR and pressurized-water reactor (PWR) plants currently in operation. Some systems in the ESBWR design differ from those in the operating BWR plants. In addition, the ESBWR design contains several innovative systems; thus, certain NUREG/CR-5750 categories do not directly apply to the ESBWR. Initiating event frequencies are estimated based on generic industry data for operating reactors, as well as on ESBWR design-specific information.

Accident sequence event tree structures and end states are defined for each initiating event category based on a review of industry PRAs and guidance documents. These are modified based on ESBWR design specifics and expected operation. Event tree nodal inputs are system fault tree logic or nodal point estimates, as appropriate. Functional success criteria are based on analysis of the ESBWR design and expected operation.

System fault trees were developed based on standard industry techniques and reflect the design of the ESBWR. System success criteria are based on analysis of the ESBWR design and expected operation.

Preinitiator and postinitiator human error probabilities were defined based on the ESBWR design and expected operation. The human error probabilities used in the model are conservative screening values extracted from industry and NRC publications.

Component failure probabilities were estimated based on generic industry data and ESBWR design-specific information. CCF data derived for the ESBWR are used where available (e.g., data regarding diesel generators, batteries, motor-operated valves [MOVs], and pumps). Generic CCF factors are used when component-specific data are not available. In order of preference, the sources used to estimate the CCF parameters are the Electric Power Research Institute (EPRI) ALWR Utility Requirements Document (URD), Revision 4, issued April 1992; NUREG/CR-5497, "Common Cause Failure Parameter Estimations," issued October 1998; and NUREG/CR-5801, "Procedure for Analysis of Common-Cause Failures in Probabilistic Safety Analysis" issued April 1993. The methodology described in NUREG/CR-4780, "Procedures for

Treating Common Cause Failures in Safety and Reliability Studies,” Volume 1 (issued January 1988) and Volume 2 (issued January 1989), applies. The multiple Greek letter (MGL) method was used to estimate the CCF probabilities.

Severe accident phenomena are explicitly addressed and are quantitatively treated. The risk-oriented accident analysis methodology (ROAAM) assesses the containment response to severe accident phenomena. A linked fault tree approach is used to address the containment systems and the ability to prevent overpressurization from loss of DHR.

To support the consequence analysis, multiple radionuclide release categories are modeled. Source terms are defined based on ESBWR thermal-hydraulic (T-H) analysis. Bounding consequence analyses are performed, showing that the ESBWR design meets NRC safety goals with sufficient margin.

The external events portion of the PRA explicitly analyzes core damage accidents initiated during power and shutdown operation for the following hazards:

- Internal floods
- Internal fires
- High winds
- Seismic events

The external events analyses are bounding assessments that are meant to show significant design margin for these hazards. The frequencies of initiating events are based on generic industry data and are applied in a bounding manner. The external events analyses use the fault trees and event trees developed for the internal events evaluations to the maximum extent possible, employing logic flags that account for the common failures induced by the external hazard events. The ESBWR seismic assessment is a seismic margin analysis (SMA). The analysis demonstrates that the ESBWR plant and equipment can withstand an earthquake with a magnitude at least 1.67 times that of the safe-shutdown earthquake (SSE).

19.1.2.1.2 Update and Maintenance of the Probabilistic Risk Assessment

The applicant described the PRA maintenance and update program in the design control document (DCD) Tier 2, Revision 9. This section summarizes the key elements of this program.

The applicant treated the ESBWR PRA model documentation as a controlled document containing the detailed information for the model. The applicant established the following set of requirements and design controls that COL applicants referencing the ESBWR design certification must implement:

- Personnel performing PRA analyses possess sufficient expertise based on training and job experience to perform the tasks.
- Personnel performing technical reviews and independent verifications of PRA analyses possess sufficient expertise based on training and job experience to perform the tasks.
- Procedures are in place that control documentation, including revisions to controlled documents and maintenance of records.

- Procedures are in place that provide for independent verifications of calculations and information used in the PRA.

For a COL applicant to maintain a PRA model that reasonably reflects the as-built and as-operated characteristics of a plant that references the ESBWR design certification, the applicant has established the following administrative controls:

- Monitor PRA inputs and collect new information.
- Maintain and upgrade the PRA model to be consistent with the as-built and as-operated plant.
- Ensure that PRA applications consider the cumulative impacts of pending changes.
- Evaluate the impact of PRA changes on previously implemented risk-informed applications.
- Maintain configuration control of the computational methods used to support the PRA model.
- Document the PRA models and procedures that implement these controls.

The maintenance process requires an independent review of the model or model elements by a qualified reviewer or reviewers. When major methodology changes or upgrades are made, outside PRA experts, such as industry peer review teams, review the PRA, and their comments are incorporated to ensure that the PRA remains current with industry practices.

19.1.2.2 Regulatory Criteria

No specific regulatory requirements govern the quality of PRAs used to support design certification. However, Regulatory Guide (RG) 1.174, Revision 1, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," issued November 2002; RG 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," issued January 2007; and Section 19.0, "Probabilistic Risk Assessment and Severe Accident Evaluation for New Reactors," of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants (LWR Edition)," issued March 2007 (hereafter referred to as the SRP Revision 2), provide guidance on how to ensure quality in PRA applications for commercial nuclear power facilities. These documents articulate the fundamental objective that the scope, technical adequacy, and level of detail of an applicant's PRA be appropriate for the application of the PRA under consideration. To meet this objective, the staff has considered the extent to which the scope, technical adequacy, and level of detail of the applicant's PRA support the Commission's objectives described above which govern the treatment of severe accidents for design certification.

19.1.2.3 Staff Evaluation

The staff reviewed the quality of the ESBWR PRA by conducting its own independent evaluation of the applicant's use of models, techniques, methodologies, assumptions, data, and computational tools, as well as evaluating the applicant's programs and processes for ensuring quality in the PRA. As with the certification of previous advanced reactor designs (e.g., the AP1000 design), the staff's review of the quality and completeness of the ESBWR PRA included

the issuance of requests for additional information (RAIs) to the applicant, followed by the evaluation of the applicant's responses to the RAIs. The staff issued over 300 RAIs to the applicant during its review of Chapter 19 of DCD Tier 2 and its 9 revisions, and NEDO-33201, "ESBWR Probabilistic Risk Assessment," and its 6 revisions (NEDO-33201 documents the ESBWR PRA; NEDO-33201 is hereafter referred to as the PRA report). The staff's initial review of these documents and subsequent review of the responses to the RAIs covered all aspects of the PRA model and the use of the model to assess the ESBWR, including assumptions, data, modeling, quantification, uncertainties, and sensitivity studies. The applicant has responded to all of these RAIs, and the staff finds the responses to be acceptable. The applicant has incorporated information provided in these RAI responses into Revision 6 of the PRA report and into DCD Tier 2, Revision 9, as appropriate.

The staff considered PRA results in the DCD Tier 2, Revisions 1 through 9, as well as results of the applicant's sensitivity, uncertainty, and importance analyses, to focus its review. The staff used applicable insights from previous PRA studies about key parameters and design features controlling risk in its review of the ESBWR. The staff placed a special emphasis on PRA modeling of novel (e.g., digital instrumentation and control [I&C]) and passive features in the design, and addressed issues related to these features, such as the impact of passive system T-H uncertainties on PRA success criteria and treatment of CCFs.

19.1.2.3.1 Success Criteria and Passive System Uncertainty

The issue of T-H uncertainties arises from the passive nature of the safety-related systems used for accident mitigation. Passive safety systems rely on natural forces, such as gravity, to perform their safety functions. Such driving forces are small compared to those of pumped systems, and the uncertainty in their values, as predicted by a best-estimate T-H analysis, can be of comparable magnitude to the predicted values themselves. Therefore, some accident sequences with a frequency high enough to impact results, but not predicted to lead to core damage by a best-estimate T-H analysis, may actually lead to core damage when PRA models consider T-H uncertainties.

In RAI 19.1.0-1, the staff requested that the applicant address the issue of passive system performance uncertainty and its effect on passive system success criteria. In response, the applicant provided the results of sensitivity studies that varied key T-H parameters for each of the passive systems to determine the effect on the criteria for a successful event sequence following a limiting initiating event. The studies addressed a number of passive systems, including the gravity-driven cooling system (GDCCS), the isolation condenser system (ICS), the automatic depressurization system (ADS), depressurization valves (DPVs), and the passive containment cooling system (PCCS). The applicant performed these studies with the Modular Accident Analysis Program (MAAP) 4.0.6 code. Table 19.1-1 of this report summarizes the results of these studies.

The applicant used the MAAP 4.0.6 code to evaluate T-H success criteria. The staff is aware of T-H modeling issues with the code that could compromise its ability to confirm the validity of the PRA success criteria involving minimal sets of mitigating equipment. The applicant justified the use of the MAAP 4.0.6 code by comparing simulations of LOCAs performed with MAAP 4.0.6 and with those using the GEH version of the Transient Reactor Analysis Code (i.e., the TRACG code). However, these benchmark calculations may not reflect T-H conditions in the reactor vessel during such accidents. The applicant applied the design-basis accident (DBA) analysis assumptions (i.e., the single-failure criterion) regarding availability of passive mitigating systems rather than the assumptions made for the PRA, which are substantially more limiting. In

RAI 19.1.0-1 S01, the staff requested that the applicant address this concern by analyzing the limiting accident scenarios, assuming PRA success criteria, with a code such as TRACG that is capable of treating the expected T-H phenomena. Such calculations would also provide a means for adequately benchmarking the MAAP 4.0.6 code for use in analyzing additional PRA accident sequences that may be affected by T-H uncertainties associated with passive systems.

Table 19.1-1. Study Results.

SYSTEM	ACCEPTANCE CRITERIA	PARAMETERS VARIED	EVENT	SUCCESS CRITERIA		
				DESIGN BASIS	BASE PRA ASSUMPTION	MIN. REQUIRED FOR SUCCESS ^a
ADS/DPV	A peak cladding temperature <2,200 °F	No. of valves valve size	Medium LOCA	7 of 8 DPVs	4 of 8 DPVs	3 of 8 DPVs
GDCS	A peak cladding temperature <2,200 °F	No. of valves valve size MAAP 4.0.6 parameters	Large LOCA	7 of 8 injection valves	2 of 8 injection valves from at least 1 of 3 pools	1 of 8 injection valves from at least 1 of 3 pools
PCCS	<ultimate containment pressure	Heat ex. heat transfer area	Large LOCA	6 of 6 heat exchangers	4 of 6 heat exchangers	2 of 6 heat exchangers
ICS		N/A ^b	N/A	3 of 4 heat exchangers	3 of 4 heat exchangers	N/A

a. The applicant based these results on the sensitivity study.

b. The applicant did not perform sensitivity analysis because it used the design-basis criteria assumed in the PRA.

The applicant identified the limiting accident scenarios assumed in the sensitivity studies and listed in Table 19.1-2. However, the applicant did not include enough information for the staff to understand the basis for selecting the limiting accident scenarios used to determine minimum success criteria. In RAI 19.1.0-1, the staff requested that the applicant provide the rationale for the accident scenarios selected, including any criteria applied in making the selections and the results of any parametric studies used to identify limiting scenarios.

The applicant did not describe how it selected key T-H parameters that could affect the results. Such parameters include decay heat rate, containment pressure, flow resistance in piping, heat transfer area and heat transfer coefficient in the ICS and PCCS, flow area through the break, safety/relief valves (SRVs), DPVs, and check valves in the GDCS. To understand the uncertainty in the determination of minimal success criteria, the staff requested, in RAI 19.1.0-1 S01, that the applicant identify the key parameters and describe how the analysis treated each one (e.g., as nominal values or bounding values) and, in cases in which nominal parameter values were used, discuss the impact on the results of the analyses if bounding parameter values had been used.

In the analyses, the applicant applied a limit of 1,204.4 degrees Celsius (C) (2,200 degrees Fahrenheit [F]) for peak cladding temperature as the acceptance criterion for avoidance of core damage. The staff finds that such a criterion is acceptable for the evaluation of PRA success criteria. However, the staff has not reviewed and approved the heat transfer, transition, and film-boiling models in TRACG needed for calculating peak cladding temperature in evaluations of emergency core cooling system (ECCS) performance. In RAI 19.1.0-1 S01, the staff requested that the applicant justify the use of TRACG for modeling clad heatup and approach to thermal limits in studies of PRA success criteria. The staff tracked RAI 19.1.0-1 as an open item in the safety evaluation review (SER) with open items.

In the response to RAI 19.1.0-1 S01, the applicant compared the performance of the TRACG and MAAP 4.0.6 codes for simulating medium- and large-break LOCA events in which the core becomes uncovered and heats up substantially before emergency cooling is started. Such conditions represent a challenge to successful mitigation of severe accidents. The results of the analyses show that the two codes predict similar behavior of key T-H parameters during the LOCA transients. The applicant provided adequate explanations for the few notable differences between the simulation results. These results adequately address the staff's concern with the original benchmark calculations.

In response to RAI 19.1.0-1 S01 1, the applicant also provided an adequate rationale for its selection of limiting scenarios, including a discussion of the criteria used for selection. The applicant also identified the key T-H parameters and described how the analysis treated each one and why it was treated in that way. In cases in which nominal parameter values were used, the applicant adequately discussed the impact on the results of the analyses, if bounding parameter values were to have been used.

In RAI 19.1.0-1 S01, the staff requested that the applicant justify the use of TRACG for modeling clad heatup and approach to thermal limits in studies of PRA success criteria. In its response, the applicant identified the key T-H phenomena, physical processes, and core parameters which directly determine the core heatup process and peak cladding temperature and provided references to topical reports which describe how TRACG models these phenomena and processes and the qualification of these aspects of TRACG using a wide range of test data. The staff finds this to be adequate justification for the use of TRACG in the study of PRA success criteria. Therefore, RAI 19.1.0-1 and the associated open item are resolved.

19.1.2.3.2 Treatment of Common-Cause Failures

In the PRA, the applicant determined importance measures for common-cause basic events and found that CCF of the following components produced the highest Fussell-Vessley (FV) importance measures (largest contributors to risk) of all the common-cause events:

- Control rod insertion
- Actuation of check valves in the GDSCS
- Actuation of squib valves in the GDSCS
- Execution of software in the I&C systems
- Actuation of squib valves in the standby liquid control system (SLCS)

In light of these results, the applicant performed a sensitivity study in which all CCFs were eliminated. This study indicated that the CDF decreased by three orders of magnitude, which confirms the importance of CCFs in the ESBWR design.

The staff reviewed the treatment of CCFs in each of the systems modeled in the PRA. The staff identified a number of issues related to common-cause grouping of components and CCF probabilities assumed for key components. The applicant addressed these issues in responses to a series of RAIs issued by the staff. In the responses, the applicant stated that it used the MGL method to quantify failure probabilities and reported the MGL parameters used to quantify the failure probability of each common-cause basic event. The MGL method is especially appropriate for the ESBWR PRA since systems in the ESBWR have common-cause groups with up to eight members. The staff considers the use of this method in the context of the general approach for treating CCFs, as described in NUREG/CR-4780, to be acceptable. The staff also finds the referenced methods for estimating CCF parameters to be acceptable.

Section 19.1.4.1.1.4 of this report discusses insights associated with the sensitivity of the PRA results to changes in specific CCF probabilities.

19.1.2.3.3 Probabilistic Risk Assessment Technical Adequacy

The staff also considered the extent to which the applicant's PRA conforms to existing consensus standards for PRA which the NRC has endorsed (e.g., American Society of Mechanical Engineers (ASME)-RA-Sb-2005, "Standard for Probabilistic Risk Assessment for Nuclear Power Plant Applications"). The applicant stated that, "where applicable, ASME-RA-Sb-2005 Capability Category 2 (CC-II) attributes are included in the analysis." In RAI 19.1-117, the staff requested that the applicant: (1) identify those high-level requirements or CC-II attributes of the standard that the ESBWR PRA did not embody, (2) address the impact on the qualitative and quantitative results of the PRA of excluding those high-level requirements or CC-II attributes of the standard that are applicable but have not been incorporated, and (3) describe any self-assessment or peer review process that has been performed for the ESBWR PRA and the resulting findings and observations. The staff tracked RAI 19.1-117 as an open item in the SER with open items.

In response, the applicant presented the results of its assessment, which showed the extent to which the ESBWR PRA incorporated CC-II attributes of ASME-RA-Sb-2005. These results included a list of the ASME standard's supporting requirements (SR), which are not considered to be applicable to the ESBWR design PRA; adequately explained why each item was not applicable; and discussed the capability level satisfied by requirements considered to be applicable to the ESBWR PRA. The applicant identified two SR which did not satisfy CC-II. The SRs considered not applicable to the ESBWR design PRA included those that pertained to treating plant operational programs that are not defined at the design stage and those that are not consistent with unique objectives of a design PRA. For each of the two SRs that did not incorporate CC-II attributes, the applicant evaluated the impact of this condition on the qualitative and quantitative results of the PRA and discussed the results of the evaluation in the response. The staff has reviewed the information provided by the applicant and finds it to be adequate to address the concern reflected in RAI 19.1-117. Therefore, RAI 19.1-117 and the associated open item are resolved.

19.1.2.3.4 Probabilistic Risk Assessment Maintenance and Update Program

RG 1.200 describes the elements of a PRA maintenance and update program that is acceptable to the staff. These elements include the following:

- Monitor PRA inputs and collect new information.

- Ensure cumulative impact of pending plant changes is considered.
- Maintain configuration control of the computer codes used in the PRA.
- Identify when PRA needs to be updated based on new information or new models/techniques/tools.
- Ensure peer review is performed on PRA upgrades.

The staff has reviewed the applicant's proposed program and finds that the program includes the key elements described in RG 1.200. The staff finds the program described by the applicant in DCD Tier 2, Revision 9, acceptable.

19.1.2.4 Conclusion

Based on its review of the information provided by the applicant, the staff finds that the quality of the applicant's PRA is sufficient for the PRA to be used to address the Commission's objectives, referenced in Section 19.1.1 of this report that govern the treatment of severe accidents for design certification. In addition, the staff finds that the applicant's PRA maintenance and update program includes the key elements described in RG 1.200 and is therefore acceptable.

19.1.3 Special Design Features

19.1.3.1 Summary of Technical Information

19.1.3.1.1 Design and Operational Features for Preventing Core Damage

Revision 6 of the applicant's PRA report and appropriate sections of the ESBWR DCD Tier 2, Revision 9, describe the design and operational features of the ESBWR aimed at preventing core damage. These features include the following:

- For prevention and mitigation of an anticipated transient without scram (ATWS) event, the ESBWR is designed with the following features:
 - An alternate rod insertion (ARI) system that utilizes sensors and logic that are diverse and independent of the reactor protection system (RPS)
 - Electrical insertion of fine motion control rod drives (FMC RDs) that also utilize sensors and logic that are diverse and independent of the RPS
 - Automatic feedwater runback under conditions indicative of an ATWS
 - Automatic initiation of the SLCS under conditions indicative of an ATWS
 - Elimination of the scram discharge volume in the control rod drive system (CRDS)

DCD Tier 2, Revision 9, Section 15.5.4, provides details on the effectiveness of these design features for addressing ATWS concerns. Given these features, ATWS contributes insignificantly to CDF and LRF, as shown in the ESBWR PRA.

- The design of the ESBWR reduces the possibility of an intersystem loss-of-coolant accident (ISLOCA) outside containment by designing to the extent practicable all piping systems, major system components (pumps and valves), and subsystems connected to the reactor coolant pressure boundary (RCPB) to an ultimate rupture strength at least equal to the full

RCPB pressure. Because of these design features of the ESBWR, ISLOCA is not a significant contributor to initiating events or accidents.

- The ESBWR design reduces the frequency and consequences of LOCAs resulting from large-diameter piping failure by removing the recirculation system altogether.
- The ICS consists of four totally independent trains, each containing an isolation condenser (IC) that condenses steam on the tube side and transfers heat to the isolation condenser/passive containment cooling system (IC/PCCS) pool, which is vented to the atmosphere. The ICs, which are connected by piping to the reactor pressure vessel (RPV), are placed at an elevation above the source of steam (i.e., vessel). When the steam is condensed, the condensate is returned to the vessel via a condensate return line. The ICS is designed as a safety-related system to remove reactor decay heat following reactor shutdown and to provide isolation in a passive way with minimal loss of coolant inventory from the reactor when the normal heat removal system is unavailable following any of the following events:
 - Sudden reactor isolation from power operating conditions
 - Station blackout (SBO) (unavailability of all alternating current [ac] power)
 - ATWS
 - LOCA

The ICS also prevents unnecessary reactor depressurization and operation of other engineered safety features that can also perform this function. In the event of a LOCA, the ICS provides additional liquid inventory from an inline condensate reservoir when the condensate return valves open to initiate the system.

- The GDSCS provides passive emergency core cooling after any event that threatens the reactor coolant inventory. Once the ADS has depressurized the nuclear boiler system (NBS), the GDSCS is capable of passively injecting large volumes of water into the depressurized RPV to keep the fuel covered over both short and long timeframes following system initiation.
- The fuel and auxiliary pools cooling system (FAPCS) is designated as a backup system for low-pressure coolant injection (LPCI). In LPCI mode, the system provides makeup water from the suppression pool to the RPV through one of the main feedwater lines after the reactor has been sufficiently depressurized. The FAPCS can also provide backup shutdown cooling (SDC) water. The FAPCS can provide cooling water during the long term using a pipe connection to convey water to the IC/PCCS pool for post-LOCA heat removal after 72 hours.
- During a total loss of offsite power, the onsite, nonsafety-related diesel generators automatically power the safety-related electrical distribution system. If, however, these diesel generators are not available, each division of the safety-related system independently isolates itself from the nonsafety-related system, and the safety-related batteries of each division provide uninterrupted power to safety-related loads of each safety-related load division. The divisional batteries are sized to provide power to required loads for 72 hours. In addition, devices that monitor the input voltage and frequency from the nonsafety system and isolate the division automatically on degraded conditions protect each division of the safety-related system. The combination of these factors in the design minimizes the probability of losing electric power from onsite power supplies as a result of the loss of power from the transmission system or any disturbance of the nonsafety-related ac system.

Because of the nature of the passive safety-related systems in the ESBWR, SBO events are not significant contributors to CDF or LRF.

- The PCCS is a safety-related, passive CHR system that maintains the containment within its design pressure and design temperature limits for DBAs, including LOCAs and post-blowdown events. The PCCS also provides a flowpath for released steam vapor back to the RPV through the GDCCS. Because the PCCS is highly reliable as a result of its redundant heat exchangers and totally passive component design, the probability of a loss of CHR is significantly reduced.
- The fire protection system (FPS) serves as a preventive feature for severe accidents in two ways. First, it reduces or eliminates the possibility of damaging fire events that could induce transients, damage mitigation equipment, and hamper operator responses. Second, it supplies a means for long-term makeup to the upper containment pools, which may be required after the first 72 hours of an accident requiring passive heat removal.

19.1.3.1.2 Design and Operational Features for Mitigating the Consequences of Core Damage and Preventing Releases from Containment

Revision 6 of the applicant's PRA report and appropriate sections of DCD Tier 2, Revision 9, describe the design and operational features of the ESBWR aimed at mitigating accident progression following core damage and preventing release of radioactivity from the containment. A summary follows:

- The ESBWR containment structure is designed to withstand a higher ultimate pressure than used for currently operating BWRs. The 95-percent confidence structural capacity (fragility) of the ESBWR primary containment system to overpressurization for the 260 degrees C (500 degrees F) steady-state thermal condition is 1.095 megapascals gauge (MPaG) (159 pounds per square inch gauge [psig]) limited by leakage at the drywell head flange as the result of bolt yielding. Under normal operating (ambient) conditions, the structural pressure capacity is 1.28 MPa (gauge) (MPaG) (186 psig) limited by tearing of the liner at the reinforced concrete containment vessel (RCCV) wall connection with the top slab. For a 538 degrees C (1,000 degrees F) transient thermal condition, the fragility is 0.89 MPaG (129 psig) limited by leakage at the bolted flange connection in the equipment hatch. The drywell head is protected from these extreme temperatures because of insulation around the RPV and restricted flowpaths from the drywell space into the area beneath the drywell head. The pool of water on top of the drywell head also keeps the flanges and closure bolts at moderate temperatures.

Within the containment are: the wetwell, including the suppression pool; an upper drywell (UDW) region surrounding the RPV; and a lower drywell (LDW) region below the RPV. Vacuum breakers are located between the wetwell air space and the UDW. The UDW and LDW regions communicate freely.

- The vacuum relief function limits the magnitude of a negative pressure differential between the drywell and the suppression pool. Three drywell-to-suppression pool vacuum breakers installed in the diaphragm floor accomplish this function. These vacuum breakers operate passively in response to a negative drywell-to-suppression pool pressure gradient and are otherwise held closed by a combination of gravity and the normally positive pressure gradient.

Four position sensors are located around the disk periphery of the primary vacuum breakers to confirm to the plant operator that the disks are securely seated. The analysis in the PRA assumes that the position switch that provides annunciation in the control room can sense a gap between the disk and the seating surface smaller than 1 square centimeter (cm²) (0.155 square inches [in.²]).

Each vacuum breaker is equipped with a diverse, redundant, passive, process-actuated check-type isolation valve, which provides isolation capability if the vacuum breaker sticks open or leaks in its closed position. The isolation valve is normally in the closed position and, like the vacuum breaker itself, is process-actuated by differential pressure between the structure and component (SC) and drywell. In this manner, the isolation valve is more like a redundant vacuum breaker than an isolation valve, and both valves would have to leak simultaneously to create a leakage path from the SC to the drywell.

- Prevention of a combustible gas deflagration in the ESBWR containment is assured in the short term following a severe accident because the ESBWR containment is maintained in an inert condition. In the longer term, the oxygen concentration increases as a result of the continued radiolytic decomposition of the water in the containment. However, the applicant's analysis of the ESBWR design shows that the time required for the oxygen concentration to increase to the deinerting value of 5 percent is significantly greater than 24 hours, which allows ample time for implementation of recovery actions.
- The containment isolation system (CIS) protects against release of radioactive materials to the environment as a result of accidents occurring in systems or components within the containment. The isolation of lines and ducts that penetrate the containment boundary provides this protection. The ESBWR containment design minimizes the number of penetrations. This impacts the severe accident response because the probability of containment isolation failure is smaller.
- The probability of a high-pressure core melt is significantly reduced by the depressurization system. The ESBWR RPV is designed with an ADS that provides automatic and effectively permanent depressurization of the reactor. In a severe accident, depressurization can prevent a high-pressure core melt ejection and the subsequent consequences. If the reactor vessel fails at an elevated pressure, fragmented core debris could be transported into the UDW. The resulting heating of the UDW could potentially pressurize and fail the drywell. Successful ADS actuation before vessel failure eliminates these direct containment heating (DCH) failure concerns. In addition, the following ESBWR containment design features mitigate the possible effects of high-pressure core melt:
- The containment is segregated into a UDW and an LDW, which communicate directly, but this design mitigates the ability of high-pressure core melt, ejected within the LDW, to reach the UDW.
 - The UDW atmosphere can vent into the wetwell through a large vent area.
 - The containment steel liner is structurally backed by reinforced concrete, which cannot be structurally challenged by DCH.
- The deluge mode of GDCS operation provides flow to flood the LDW when the temperature in the LDW increases enough to indicate RPV failure and core debris in the LDW. Of the four main deluge lines, one is available from each of the GDCS pools, A and D, and two from GDCS pool BC. Each main line forks into three injection lines for a total of 12; each

injection line has one squib valve. Flooding of the LDW after the introduction of core material minimizes the potential for energetic fuel-coolant interaction (FCI) at RPV failure. Covering core debris with water provides scrubbing of fission products released from the debris and cools the corium, thus limiting potential core-concrete interaction (CCI). The basemat internal melt arrest and coolability (BiMAC) device gives additional assurance of debris bed cooling by providing an engineered pathway for water flow through the debris bed.

- The BiMAC device is a passively cooled barrier to core debris on the LDW floor. This boundary is provided by a series of side-by-side inclined pipes, forming a jacket, which is passively cooled by natural circulation when subjected to thermal loading. The GDCS pools supply water to the BiMAC device via squib valves that are activated on the deluge lines. The timing and flows are such that cooling becomes available immediately upon actuation, and the chance of flooding the LDW prematurely, to the extent that this opens up a vulnerability to steam explosions, is remote. The core debris coolability analysis shows that the BiMAC device is effective in containing the potential core melt released from the RPV in a manner that ensures long-term coolability and stabilization of the resulting debris.

19.1.3.1.3 Design and Operational Features for Mitigating the Consequences of Releases from Containment

Revision 6 of the applicant's PRA report and appropriate sections of DCD Tier 2, Revision 9, describe the design and operational features of the ESBWR aimed at mitigating the consequences of a release of radioactivity from the containment. The following describes and summarizes these features:

- The design of the ESBWR containment provides for holdup and delay of fission product release should the containment integrity be challenged. Delay in fission product release helps reduce the amount of radioactivity released and allows more time for implementation of emergency preparedness actions which lower the dose to the population.
- The deluge mode of GDCS operation provides flow through the BiMAC device to flood the LDW when the temperature in the LDW increases enough to indicate RPV failure and core debris in the LDW. Covering core debris with water provides scrubbing of fission products released from the debris and helps reduce the magnitude of any release to the outside environment.

19.1.3.1.4 Uses of the Probabilistic Risk Assessment in the Design Process

In RAI 19.1-73, the staff requested that the applicant address the use of the PRA in the design process and discuss representative examples of ways in which the addition or modification of design features or operational requirements enhance the ESBWR design. The applicant provided this information in Section 18 of the PRA report, Revision 4, which DCD Tier 2, Revision 6, referenced.

In its response to the staff's request, the applicant provided a list of design features that contribute to the low CDF and balance the risk profile of the ESBWR. Key examples include the following:

- The ESBWR design reduces the reliance on ac power by using 72-hour batteries for several components. A diesel-driven pump has been added as a diverse makeup capability. The

core can be kept covered without any ac sources for the first 72 hours following an initiating event. This ability significantly reduces the consequences of a loss of preferred (i.e., offsite) power initiating event. These features combined with passively designed front-line safety systems eliminate SBO as a significant contributor to risk.

- ATWS events are low contributors to plant CDF because of the improved scram function and passive boron injection.
- The ESBWR design reduces the frequency and consequences of LOCAs resulting from large-diameter piping failure as compared to those in BWR plants currently operating because the ESBWR design does not include a primary coolant recirculation system and its associated large-diameter piping.
- The design of the ESBWR reduces the possibility of a LOCA outside the containment because, to the extent practical, the ultimate rupture strength of all piping systems, major system components (e.g., pumps and valves), and subsystems connected to the RCPB has been set at least equal to the full RCPB pressure.
- The probability of a loss of CHR is significantly reduced because the redundant heat exchangers and completely passive component design of the PCCS make it highly reliable.

The applicant used its PRA to identify and quantify various alternatives for improving the ESBWR design in comparison to the reliability of certain design features found in currently operating BWRs. For example, fire suppression piping has been rerouted based on the risk assessment results. This reduces the probability of internal flooding, which can disable multiple trains of equipment. The following are examples of PRA-based changes incorporated in the ESBWR design that have contributed to a significant improvement in plant safety:

- The design includes additional redundant, physically separated flowpaths to the low-pressure injection and suppression pool cooling lines in response to fire analysis.
- The applicant determined the loads to be served by the diverse protection system (DPS), which supplies diverse control signals to safety functions.
- The applicant improved the design of digital controls to reduce the likelihood of inadvertent actuation of specified systems.
- The design includes additional redundant supply valves for ICS and PCCS pool makeup.
- The design includes additional redundant drainline valves for the ICS to eliminate a dependency on power supplies.
- The applicant changed the routing of fire suppression piping to reduce the likelihood of room flooding.
- The applicant determined the appropriate locations of control and instrumentation cabinets and power supplies to ensure physical separation.
- The design includes the BiMAC device to reduce the consequences of severe accidents.

19.1.3.2 Regulatory Criteria

The staff has considered the special design features of the ESBWR design with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report. The following two objectives are especially relevant to the evaluation of design features aimed at reducing risk:

1. Assess the balance between features of the design that prevent and mitigate accidents.
2. Determine whether the plant design represents a reduction in risk compared to the risk from existing operating plants.

No specific regulatory requirements govern the special design features used to support design certification. However, the staff has used applicable guidance from SRP Section 19.0, Revision 2, 2007, in its review.

19.1.3.3 Staff Evaluation

Based on the information provided by the applicant and summarized herein, it is clear that the ESBWR design includes many features that can prevent severe accidents and many that can mitigate the consequences of severe accidents. For example, the design includes features for the specific purpose of reducing the likelihood of an ATWS, loss of DHR event, and core uncovering during LOCAs and ISLOCAs, as well as fires and floods. All of these events have contributed significantly to risk in current operating plants and required design and operational changes after the facilities were built and operating. In addition, the ESBWR design includes features that address the following specific containment failure modes:

- DPVs and structural improvements to the containment to address DCH from high-pressure melt ejection (HPME)
- GDCS deluge and the BiMAC device to address potential melt-through of the containment
- Fewer containment penetrations to reduce the likelihood of containment bypass

The staff finds that the applicant has provided an adequate balance between design features that prevent accidents and those that mitigate accidents.

In its response to RAI 19.1-73, the applicant described the differences and similarities between the ESBWR design and the current generation of operating BWRs. It is clear from this comparison, as well as the above summary of ESBWR design features, that the ESBWR standard design has evolved from current BWR technology through the incorporation of several passive design features and other design changes intended to make the plant safer. The information provided in response to RAI 19.1-73, and summarized previously, indicates that the applicant has included several features in the ESBWR design to address the major contributors to core damage in the current generation of BWRs (i.e., SBO, ATWS, and LOCA). In addition, the ESBWR design includes features to address specific containment failure modes. Therefore, RAI 19.1-73 is resolved.

19.1.3.4 Conclusion

Based on the substantial number of design improvements in areas that have traditionally been strong contributors to risk, the staff concludes that the ESBWR design reflects a reduction in risk compared to the design of currently operating BWRs. This conclusion is consistent with the quantitative results of the ESBWR PRA, which indicate a much lower total CDF and LRF compared to those of BWRs currently operating.

19.1.4 Safety Insights from the Internal Events Probabilistic Risk Assessment for Operations at Power

19.1.4.1 Results and Insights from the Level 1 Internal Events Probabilistic Risk Assessment

The staff reviewed the results of the applicant's Level 1 PRA for at-power operations and found them to be mostly quantitative and lacking an adequate discussion of the following topics:

- Major contributors to risk
- Key qualitative risk insights for the ESBWR
- Major design and operational features that contribute to reduced CDF for the ESBWR design compared to BWR plants currently operating

The applicant provided additional information on the items listed below in response to RAI 19.1-68 and incorporated this information into Revision 5 of the PRA report:

- Discussion of key risk insights and key assumptions in the PRA model
- Discussion of ESBWR design features that reduce risk
- Comparison of BWR versus ESBWR PRA prevention and mitigation functions
- Descriptions of the top 10 accident sequences and top 200 cutsets contributing to CDF
- Results of a quantitative assessment of the risk importance of SSCs
- Results and insights from 16 sensitivity studies

The applicant's response provides adequate detail to resolve the staff's concern. Therefore, RAI 19.1-68 is resolved.

19.1.4.1.1 Summary of Technical Information

The applicant reports a total CDF resulting from internally generated accident sequences during power operations of $1.65 \times 10^{-8}/\text{yr}$.

The applicant identified the following key risk insights regarding the ESBWR design:

- Dominant sequences typically do not contain independent component failures. Instead, they consist of CCFs that disable entire mitigating functions. It is important to note that multiple mitigating functions must fail in the dominant sequences. A single common-cause event is not sufficient to directly result in core damage.
- The ESBWR Level 1 PRA CDF is significantly impacted if the nonsafety-related systems are not credited. If the analysis takes credit for all key backup nonsafety systems, the focused

Level 1 PRA results are reduced by almost two orders of magnitude. However, the impact to the CDF can be minimized by about one order of magnitude if the analysis credits only the availability of the DPS (including surrogate logic for the DPS signal for isolation of the main steam isolation valve [MSIV]).

- ATWS events are low contributors to plant CDF because of the improved scram function and passive boron injection.

Section 18 of Revision 6 of the PRA report discusses additional insights.

19.1.4.1.1.1 Significant Accident Sequences Leading to Core Damage

Section 19.2.3.1.1 of DCD Tier 2, Revision 9, and Section 7 of the PRA report, Revision 6, describe the significant accident sequences leading to core damage. The 10 most significant sequences, which constitute approximately 65 percent of the CDF, are summarized below:

- General Transient with ATWS (approximately 13 percent of CDF)
 - Scram fails
 - SLCS fails
- Inadvertent Opening of a Relief Valve (approximately 10 percent of CDF) where the following actions occur:
 - Scram is successful
 - High-pressure injection fails
 - Depressurization is successful
 - Low-pressure injection fails
- Inadvertent Opening of a Relief Valve (approximately 10 percent of CDF) where the following actions occur:
 - Scram is successful
 - High-pressure injection fails
 - Depressurization fails
- Medium Liquid LOCA (approximately 5 percent of CDF)
 - Scram is successful
 - Vacuum breakers pressure suppression is successful
 - Depressurization is successful
 - Low-pressure injection fails
- General Transient with ATWS (approximately 5 percent of CDF)
 - Scram fails
 - One or more SRVs sticks open
 - Maintenance of RPV water level fails
- Medium Liquid LOCA (approximately 5 percent of CDF)
 - Scram is successful
 - Vacuum breakers pressure suppression is successful
 - Depressurization is successful

- Low-pressure injection fails
- Medium Liquid LOCA (approximately 5 percent of CDF)
 - Scram is successful
 - Vacuum breakers pressure suppression is successful
 - Depressurization fails
- Small Steam LOCA (approximately 4 percent of CDF)
 - Scram is successful
 - Vacuum breakers pressure suppression is successful
 - Depressurization is successful
 - Low-pressure injection fails
 - Control rod drive (CRD) injection fails
- Small Liquid LOCA (approximately 4 percent of CDF)
 - Scram is successful
 - ICs are successful
 - Depressurization is successful
 - Vacuum breakers pressure suppression is successful
 - Low-pressure injection fails
 - CRD injection fails
- Loss of preferred power (LOPP) (approximately 4 percent of CDF)
 - Scram is successful
 - ICs fail
 - SRV open and reclosure is successful
 - Depressurization fails
 - CRD injection fails

19.1.4.1.1.2 *Leading Initiating Event Contributors to Core Damage from the Level 1 Internal Events Probabilistic Risk Assessment*

Transients contribute the most to CDF (approximately 59 percent). The most significant groups of transient initiators are the following:

- Inadvertent stuck-open relief valve (22 percent)
- General transients (19 percent)
- Loss of offsite power transients (10 percent)
- Loss of feedwater transients or instrument air (5 percent)

LOCAs that occur inside containment contribute approximately 39 percent to the CDF. The most significant LOCA initiators with respect to CDF contribution are the medium liquid LOCA, small steam LOCA, and small liquid LOCA, which, together, represent 35 percent of the overall CDF, thus becoming the third, fourth, and sixth most important initiating events, respectively. The large contribution of these LOCA events is caused primarily by feedwater isolation, which occurs by design in scenarios in which high drywell pressure exists, and CRD isolation, which occurs by design in scenarios in which high drywell pressure and high LDW level exist. Finally, breaks outside containment represent less than 2 percent of the total value of the CDF.

An examination of the relative contributions to the CDF of the accident classes used to define the Level 1 end states of the event trees offers another perspective on the Level 1 PRA results. Core damage events occurring at low RPV pressures with the containment initially intact account for approximately 65 percent of the CDF. Core damage events occurring at high RPV pressures with the containment initially intact account for approximately 18 percent of the CDF. Core damage events that involve a failure-to-insert negative reactivity account for about 16 percent of the CDF. Events that involve a radiological release path that bypasses the containment at the time of core damage account for less than 1 percent of the CDF.

19.1.4.1.1.3 *Risk-Significant Equipment/Functions/Design Features, Phenomena/Challenges, and Human Actions*

As part of its PRA, the applicant performed a study of the sensitivity of the PRA results to individual system failures. Based on this study, the applicant identified the following systems as the most important from a risk perspective:

- ADS
- ICS
- CRDS
- SLCS
- Safety-related and nonsafety-related I&C systems
- RPS
- GDCS

Important operator actions involve recognizing the need for depressurization or providing low-pressure injection in particular scenarios, failure to restart feedwater pumps during certain ATWS scenarios, failure to open the vent in the ICS when required, pre-initiator valve positioning errors in the CRDS, and failure to recognize the need to makeup the ICS and PCCS pool levels. The human factors engineering program incorporates information on important operator actions.

Section 19.1.3 of this report discusses important design features.

19.1.4.1.1.4 *Insights from the Uncertainty, Importance, and Sensitivity Analyses*

The applicant conducted a series of sensitivity studies on the Level 1 PRA model and stated that the purposes of these studies were to (1) develop a better understanding and provide insights related to CDF generated through model analysis and (2) provide guidance for ongoing design and operational activities in the consideration of overall risk impact. Table 19.1-2 summarizes these studies and their key results.

Key insights derived from these studies are as follows:

- Sensitivity study results indicate that changes in the human error failure probabilities, particularly pre-initiators, have the potential to impact CDF.
- An increase of the vacuum breaker and backup valve failure rate of one order of magnitude causes the CDF to increase by approximately 10 percent.
- Changes to squib valve failure data, particularly when used for the ADS and GDCS functions, have a significant impact because of their contribution to passive safety features.

Table 19.1-2. Sensitivity Studies and Key Results.

SENSITIVITY STUDY	DESCRIPTION	IMPACT ON CDF^a
Human Reliability	All actions fail; all actions succeed	< 100-fold change
Common-Cause Failure	All CCF eliminated	1,000-fold decrease
Squib Valve Failure Rates	Failure rates increased by factor of 2 in key systems	Substantial increase
Test and Maintenance (T&M) Unavailability	All T&M activities fail; increase unavailability by factor of 10	Small increase; negligible increase
SLCS Success Criteria	One train for success instead of two	Small decrease
Component Type Code Data	Basic event data for six component groups increased by factor of 10	Little or no change
SRV Common-Cause Factors	One common-cause group versus one for each of the two valve functions (ADS and overpressure protection)	No change
SPC & LPCI Success Criteria	Two trains for success instead of one	Small increase
Turbine Bypass Valve Success Criteria	Six of 12 versus four of 12 valves for success	Negligible
LOCA Frequency	All frequencies doubled	Small increase
LOCA-IC Frequency	Frequency of LOCAs outside containment increased to reflect more piping outside	No change
CRD Injection Postcontainment-Failure	CRD assumed to fail if containment fails	No change
Accumulators	All accumulators supporting pneumatic components fail	100-fold increase
Vacuum Breakers	Failure rate increased by factor of 10	Slight increase
System Importance	Importance measures computed for 40 systems	20 systems with FV > 0.01 (risk significant)

SENSITIVITY STUDY	DESCRIPTION	IMPACT ON CDF ^a
Demand for Passive Systems	CDF for sequences having passive component failure compared to CDF for sequences having passive component success	Sequences involving failure of ICS components are large fraction of CDF

a. The applicant provided this assessment.

19.1.4.1.2 Regulatory Criteria

The staff has considered the results and insights from the Level 1 PRA with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report. The following four objectives for the applicant's use of the design PRA are most relevant to the evaluation of results and insights from the Level 1 PRA:

- (1) Reduce or eliminate the significant risk contributors of existing operating plants that are applicable to the new design by introducing appropriate features and requirements.
- (2) Identify risk-informed safety insights based on systematic evaluations of the risk associated with the design such that the applicant can identify and describe (a) the design's robustness, levels of defense-in-depth, and tolerance of severe accidents initiated by either internal or external events and (b) the risk-significance of specific human errors associated with the design.
- (3) Determine how the risk associated with the design compares against the Commission's goal of less than 1×10^{-4} /yr for CDF.
- (4) Determine whether the plant design represents a reduction in risk compared to existing operating plants.

No specific regulatory requirements govern the safety insights used to support design certification. However, the staff used applicable guidance from SRP Section 19.0, Revision 2 to conduct its review.

19.1.4.1.3 Staff Evaluation

The applicant has reported a CDF of 1.65×10^{-8} /yr for internal events initiated during power operation. In contrast, comparable CDFs for the majority of existing BWR operating plants reported in the individual plant examination (IPE) program (see NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance," issued October 1997) are between 1×10^{-6} /yr and 1×10^{-4} /yr. This difference in CDFs reflects the differences in design between currently operating BWRs and the ESBWR, as discussed below.

In NUREG-1560, which reports the results of the IPE program, the staff identified CDFs for the major initiating event categories and design features and human actions that had a significant impact on the contribution of those events to the CDF. The comparison of these design features and human events with the ESBWR design in Table 19.1-3 provides insight regarding the difference in CDFs.

**Table 19.1-3. Comparison of Design Features in
Existing BWRs and the ESBWR by Event Category.**

EVENT CATEGORY	DESIGN FEATURES IN EXISTING BWRs THAT SIGNIFICANTLY AFFECT CDF (NUREG-1560)	RELEVANT ESBWR DESIGN FEATURES
SBO	Availability of cooling systems that are independent of ac power, battery life, and overall reliability of ac and dc power systems (reduces CDF)	During a total loss of offsite power at an ESBWR-based plant, the safety-related electrical distribution system is automatically powered from the onsite nonsafety-related diesel generators. If these diesel generators are not available, then each division of the safety-related system independently isolates itself from the nonsafety-related system, and the safety-related batteries of each division provide power to safety-related loads of each safety-related load division. The divisional batteries are sized to provide power to required loads for 72 hours. In addition, the ESBWR design includes safety-related DHR systems that do not require ac power to operate. Consequently, SBO events are not significant contributors to CDF for the ESBWR.
Transients with Loss of Injection Capability	Degree of dependency of injection systems on support systems; low dependency reduces CDF	The ESBWR design includes a large number of injection systems (i.e., GDSCS, CRD, FAPCS, and the fire water system). In addition, the GDSCS is designed to run with no dependency on support systems for the first 72 hours following an accident. Also, unlike current operating plants, injection into the reactor vessel with a diesel-driven fire pump is part of the ESBWR design.
Transients with Loss of DHR Capability	Degree of dependency of DHR systems on support systems; low dependency reduces CDF The capability of the ECCSs to pump saturated water; reduces CDF	DHR systems in the ESBWR include the ICS and the PCCS, which are passive systems designed to run with no dependency on support systems for the first 72 hours following an accident. ECCSs in the ESBWR are gravity driven and do

EVENT CATEGORY	DESIGN FEATURES IN EXISTING BWRs THAT SIGNIFICANTLY AFFECT CDF (NUREG-1560)	RELEVANT ESBWR DESIGN FEATURES
	Use of the RWCU as an alternative DHR system; reduces CDF Ability to replenish water sources outside containment for use in long-term cooling	not rely on pumps. Adequate cooling water inventory is guaranteed for 72 hours, and after that, makeup is provided, by design, using the diesel-driven fire pump.
LOCA	High redundancy and diversity in injection systems; reduces CDF	The ESBWR design has high redundancy and diversity in injection systems. It includes passive injection systems, motor-operated active injection systems, and diesel- driven injection systems.
ATWS	Reliance on success of human actions; increases CDF	In the ESBWR, some human actions have been automated (e.g., automatic initiation of SLCS). In addition, the ESBWR adds several important ATWS mitigation features, including the ARI system, FMCRD insertion capability, automatic feedwater runback, and elimination of the scram discharge volume.

As described in Table 19.1-3, the ESBWR includes a number of new design features and design modifications to specifically address issues important to risk in previous BWR designs. It is reasonable to expect, based on these changes, that the CDF for the ESBWR would be substantially lower than the CDF for currently operating plants. However, some of these features and changes rely on new technology with uncertain reliability (e.g., squib valves in passive systems and digital I&C systems). The applicant has addressed this by examining the sensitivity of the CDF to changes in reliability data for these features or by choosing data believed to be conservative or bounding and by examining the impact of uncertainty in passive system success criteria on CDF. Table 19.1-2 summarizes sensitivity studies involving squib valve failure rate and CCF data. Section 19.1.2.3.1 of this report documents the staff's evaluation of passive system success criteria.

19.1.4.1.4 Conclusion

The staff has reviewed the results and insights derived from the Level 1 PRA and sensitivity studies. Based on this review, the staff concludes that the applicant has performed adequate systematic evaluations of the risk associated with the design and used them to identify risk-informed safety insights in a manner consistent with the Commission's stated goals.

The staff has considered the reported CDF for the ESBWR baseline PRA (i.e., $1.65 \times 10^{-8}/\text{yr}$) in relation to CDFs reported for currently operating BWRs, the risk-significant design differences between the ESBWR and currently operating BWRs, and the applicant's studies of the

sensitivity of the computed CDF to changes in modeling and data in the PRA. Based on these considerations, the staff concludes that the methodology and results of the Level 1 risk analysis described in the ESBWR PRA are acceptable and meet the Commission's goal of less than 1×10^{-4} /yr for core damage. The staff concludes that the ESBWR design represents a reduction in risk compared to existing operating BWR plants.

As discussed above, the applicant has incorporated substantial features into the ESBWR design specifically aimed at reducing the risk from SBO and LOCA events. As a result, the staff concludes that the applicant has reduced significant risk contributors of existing operating plants that are applicable to the new design by introducing appropriate features and requirements, consistent with the Commission's stated goals.

19.1.4.2 Results and Insights from the Level 2 Internal Events Probabilistic Risk Assessment (Containment Analysis)

The following sections present results and insights from the Level 2 portion of the ESBWR full-power internal events PRA. These sections address the frequency of the various accident classes considered in the Level 2 analysis, the frequency and conditional containment failure probability (CCFP), a breakdown of containment failure frequency in terms of important containment failure and release modes, and a summary of the risk-significant insights from the Level 2 PRA and the supporting sensitivity analyses.

19.1.4.2.1 Summary of Technical Information

The ESBWR has a very low LRF (1.4×10^{-9} per reactor-year for at-power internal events and 4.7×10^{-9} per reactor-year for all at-power events, respectively). Accident sequences leading to a large release are unlikely but have broad bands of uncertainties. Consequently, the applicant used a bounding approach, rather than a best-estimate method, for assessing containment performance. In Section 11.3.2.5 of the PRA, Revision 6, the applicant also estimated that the ESBWR passive containment design is sufficiently robust to effectively mitigate the consequences of severe accidents with a low attendant CCFP for internal events approaching 0.08, and an overall CCFP for all at-power events of about 0.11.

The applicant identified the following key insights relevant to preventing or mitigating large releases to the environment:

- The containment provides a highly reliable barrier to the release of fission products after a severe accident, with the dominant release category being that defined by technical specification leakage (TSL).
- The ESBWR is designed to minimize the effects of direct containment heat, ex-vessel steam explosions (EVEs), and CCI. Its containment is designed to a higher ultimate pressure than that of conventional BWRs.

The applicant also stated that, given a severe accident, venting would occur when the containment pressure reaches 90 percent of the ultimate containment strength.

19.1.4.2.1.1 Level 2 Probabilistic Risk Assessment Methodology

The Level 2 PRA analysis focuses on the response of the containment and its systems during the progression of severe accidents. The methodology used includes binning the Level 1 PRA

results into a manageable number of accident classes and constructing and quantifying CETs, simulating severe accident progression and containment challenges for a number of accident sequences that represent the significant core damage scenarios, and assigning representative sequence results into release categories for the purpose of defining the end states and determining the pathways of radioisotopes into the environment. The applicant evaluated the containment response for a 24-hour period following the onset of core damage. The CCFP is determined from the Level 2 PRA.

Results of the CET analyses provide the necessary input to model and assess fission product transport through the containment, calculate radiological release fractions associated with containment release paths, and determine potential consequences associated with each fission product release category.

The Level 1 PRA results are grouped into a set of classes for input into the CET evaluation. The results of the CET evaluation are then grouped into a set of “release categories” for use as source terms for the offsite consequence analysis and, subsequently, risk integration.

The applicant created a Level 2 PRA quantification model with the same basic methodology as the Level 1 model. In the Level 2 model, the initiator is actually a gate under which the appropriate Level 1 sequences are binned. Effectively, the integrated model is a combination of both the Level 1 and Level 2 PRA models. As such, all initiator impact is preserved throughout the quantification, and no special treatment is required for scenarios such as LOPP. Each of the Level 2 CETs models the nodes as either a fault tree to represent system functions or a basic event with a point estimate to represent phenomenological effects.

The fault trees may be completely independent of Level 1 sequences (such as the GDCS deluge system) or contain dependencies (such as short-term CHR). Integrating the Level 2 PRA with the Level 1 PRA as a single, one-time quantification model allows the results to correctly reflect all dependencies and initiator impacts.

19.1.4.2.1.1.1 Containment Event Trees

To determine the conditional system failure probabilities values used on the CET branches, the 132 listed Level 1 quantified accident sequences above the cutoff level of $1.0 \times 10^{-15}/\text{yr}$ are sorted into subclasses based on the Level 1 accident class binning and the water level in the LDW at the time of vessel breach (to determine the fraction of sequences that are susceptible to EVE).

The Level 1 accident classes, discussed in Section 7 of the PRA, are as follows:

- Class I: Vessel failure occurs at low pressure (less than 1 MPa) (145 pounds per square inch [psi]) (65 percent of CDF).
- Class II: Containment failure precedes core damage (0.2 percent of CDF).
- Class III: Vessel failure occurs at high pressure (greater than 1 MPa) (145 psi) (17 percent of CDF).
- Class IV: Vessel failure occurs at low pressure; core damage results from failure to insert negative reactivity in ATWS conditions (16 percent of CDF).

- Class V: Core damage occurs with the RPV open to the environment because of breaks outside containment (0.5 percent of CDF).

As shown in Table 19.1-4, a set of rules based on break size, location, and injection status is used to bin the low-pressure Class I and Class IV sequences into three subgroups according to the water level existing in the LDW at vessel breach. If the water is above 1.5 meters (m) (4.92 feet [ft]), the applicant conservatively assumed that the pedestal fails as the result of steam explosion. If the water level is between 0.7 and 1.5 m (2.30 and 4.92 ft) a steam explosion is possible, but failure of the pedestal is physically unreasonable². If the water level is below 0.7 m (2.30 ft), the applicant determined that a steam explosion impulse would not challenge the containment structure.

Table 19.1-4. Assignment of Level 1 Accident Sequences to Level 2 Containment Event Tree Entry Events.

LEVEL 1 ACCIDENT CLASS	CLASS CDF (PER YEAR)	CLASS SUMMARY	LDW WATER LEVEL BIN	LEVEL 2 CET ENTRY EVENT	CET- ASSIGNED CDF (PER YEAR)	CDF FRACTION
Class I	1.1×10^{-8}	Sequences with RPV failure at low pressure	Low/Dry	I_LD	7.8×10^{-9}	0.47
			Medium	I_M	2.1×10^{-9}	0.13
			High	I_H	7.9×10^{-10}	0.05
Class II	6.4×10^{-11}	Containment failure preceding core damage	No CET required as the containment is failed in these sequences before core damage			
Class III	2.9×10^{-9}	Sequences with RPV failure at high pressure	Low/Dry	III_LD	2.9×10^{-9}	0.17
Class IV	2.7×10^{-9}	Sequences involving failure to insert negative reactivity	Low/Dry	IV_LD	2.7×10^{-9}	0.16
			Medium	IV_M	3.9×10^{-12}	< 0.01
			High	IV_H	1.1×10^{-11}	< 0.01
Class V	8.1×10^{-11}	Breaks outside of containment	No CET required as there is direct communication between the RPV and the environment			

² "Behavior is physically unreasonable and violates well-known reality. Its occurrence can be argued against positively." (Theofanous and Yang, 1993)

The applicant used the CETs to evaluate the complete spectrum of potential challenges to containment integrity. They address both containment system functions relevant to mitigating the overpressure and bypass challenges and phenomenological effects. The analysis used the Level 1 sequence bins as the initiators, or entry events, to the CETs, which were constructed using point estimates for phenomenological effects and appropriate logic to account for mitigating system success or failure by establishing the logically possible containment responses. Finally, the end states of the CETs, which are termed “release categories,” were defined. The source term evaluation used release categories, which represent meaningfully different outcomes to the containment challenge.

The seven CET entry events are associated with the accident classes shown in Table 19.1-4 above. The event trees include top events, depending on the class, that address the following:

- Phenomena
 - DCH
 - EVE
 - dry and wet molten core-coolant interaction (MCCI)
 - core debris cooling
- System Functions
 - CIS
 - GDCS deluge function
 - vapor suppression function
 - CHR, short term
 - CHR, long term
 - actuation of containment venting

Either a phenomenological basic event with an assigned point value or a system fault tree represents each of the CET nodes. Section 21 of the PRA describes the treatment of the phenomenological events by the ROAAM procedure. The events addressed include containment performance against DCH, containment and BiMAC performance against EVE, and containment and BiMAC performance against basemat melt penetration (BMP) and overpressurization from gases produced from CCI.

The applicant conducted a complete Level 2 fault tree analysis for the GDCS deluge system. Because the deluge system is completely independent of all other plant systems, it is also independent of all Level 1 sequences.

Conditional (depending on initiator effects and Level 1 sequences) probabilities for the failure branches of the other system functions in the CETs are calculated by means of the Level 2 fault trees developed for these nodes.

19.1.4.2.1.1.2 Simulation of Accident Progression and Containment Challenges

As discussed above, the Level 1 analysis grouped severe accidents into five categories. With the exception of Class V accidents, in which the containment is completely bypassed, a single dominant sequence represents each of the accident classes for detailed modeling. This allows evaluation of the containment response to the complete spectrum of accidents contributing to the CDF.

Table 19.1-5 of this report (adapted from Table 8.3-1 of the PRA) identifies the sequences used to represent each accident class. The “core damage sequence descriptor” used in the table derives from the results of the Level 1 analysis. The core damage descriptor key (used in Tables 19.2-5 and 19.2-6 of this report) is as follows:

MLi: medium liquid break (injection line)
T: transient
T-AT: transient without negative reactivity insertion
nCHR: no CHR
nDP: no depressurization
nIN: no injection
FR: filtered release (controlled vent)
TSL: technical specification leakage
NA: not applicable

Table 19.1-5. Representative Core Damage Sequences.

ACCIDENT CLASS	CORE DAMAGE SEQUENCE DESCRIPTOR	SEQUENCE SUMMARY
I	T_nIN	Transient initiator followed by no short- or long-term coolant injection. ADS functions. ICS not credited. PCCS available, but no active CHR (FAPCS). GDACS/BiMAC function successful.
II	MLi_nCHR	Medium liquid line break. GDACS injection line break. System is depressurized and injection systems function. CHR not available.
III	T_nDP_nIN	Transient initiator followed by no short- or long-term coolant injection. RPV not depressurized; pressure controlled at relief valve setpoint. ICS not credited. PCCS available, but no active CHR (FAPCS). GDACS/BiMAC function successful.
IV	T-AT_nIN	Transient followed by failure to insert negative reactivity. ICS not credited. RPV not initially depressurized (ADS inhibit successful). SLCS ineffective or unavailable. Feedwater runback successful. No short- or long-term coolant injection. PCCS available, but no active CHR (FAPCS). GDACS/BiMAC function successful. RPV depressurization assumed to be successful before RPV failure.
V	None	No representative sequence assigned for containment evaluation because Class V events involve direct communication between the RPV and environment.

The representative sequences are based on the Level 1 results presented in Section 7 of the PRA and the definitions of the Level 1 sequence bins. For example, Table 7.2-3 of the PRA indicates that about 74 percent of the Class I frequency is associated with stuck-open relief valve (T-IORV), large feedwater LOCA (LL-S-FDWA/B), or small and medium LOCA (SL-, ML-)

sequences. From the perspective of modeling the containment response to a severe accident, all Class I sequences can be represented as a transient with loss of injection (T_nIN) and successful depressurization. The applicant used a similar approach in selecting the representative sequences for the other accident classes.

Table 8.3-2 of the PRA couples each representative core damage sequence with various release categories and their associated frequencies. The resulting scenarios are assigned containment response sequence descriptors to summarize the core damage and containment release information, thus providing additional information by presenting the release category frequency in terms of the contribution from each accident class.

To determine the key characteristics of the containment response to a severe accident, the applicant developed an ESBWR simulation model using MAAP 4.0.6, including models for the important phenomena that might occur in a severe LWR accident. The model offers insights into the timing of severe accident progression, the containment pressure-temperature response, and ultimately the potential source term if the containment were to fail. The source term calculations support the characterization of the timing and release magnitude of the release categories, which are used as input to the Level 3 PRA calculations. Table 19.1-6 shows the results of MAAP 4.0.6 simulations of the ESBWR representative sequences. Appendix 8B to the PRA shows graphs of many additional representative sequence results, including pressures, temperatures, water levels, and hydrogen concentrations, to provide complete documentation of the containment analysis.

Table 19.1-6. Summary of Results of Severe Accident Sequence Analysis.

SEQUENCE DESCRIPTOR	RPV DEPRESS. INITIATED (SECONDS)	CORE UNCOVERED (HOURS)	ONSET OF CORE DAMAGE (HOURS)	RPV FAILURE (HOURS)	DELUGE ACTUATED (HOURS)	DRYWELL PRESSURE 24 HOURS AFTER CORE DAMAGE (MPA) [psi]
T_nIN_TSL	621	0.50	0.8	7.5	7.5	0.81 [117.47]
T_nIN_nCHR_FR	614	0.49	0.9	7.7	7.7	0.91 [132.0]
MLi_nCHR	123	>72	>72	>72	NA	NA
T_nDP_nIN_TSL	NA	0.92	1.5	5.9	5.9	0.86 [124.73]
T_nDP_nIN_nCHR_FR	NA	0.92	1.5	6.7	6.7	1.01 [146.4]
T-AT_nIN_TSL	1,123	0.1	0.3	5.6	5.6	0.81 [117.47]
T-AT_nIN_nCHR_FR	1,124	0.1	0.3	5.8	5.8	1.04 [150.8]

The applicant did not use MAAP 4.0.6 to estimate the probability of containment failure from DCH, EVE, or BMP events caused by BiMAC failure. Instead, the applicant used the ROAAM procedure, as reported in Section 21 of the PRA.

Accident Class I involves sequences in which the RPV fails at low pressure, and Accident Class III involves sequences in which the RPV fails at high pressure. Accident Class IV includes sequences that are initiated by an ATWS and followed by failure to achieve subcriticality. Transient sequences in which there is no core injection dominate all three classes. The analysis used sequences T_nIN, T_nDP_nIN, and T-AT_nIN to evaluate the containment response to Class I, III, and IV events, respectively.

Accident Class II involves sequences in which containment failure precedes RPV failure. After containment failure, RPV makeup capability is assumed to be lost because the gradual boiloff of water in the passive systems may result in damage to piping connections which would render active makeup systems unavailable. As a result, core damage and RPV failure occur after containment failure. As shown in representative sequence MLi_nCHR, core damage does not occur during the first 72 hours after the accident.

Sequence T_nIN_TSL (Represents Class I)

The T_nIN sequence simulates a transient initiated by an LOPP in which no short- or long-term coolant injection to the RPV by the feedwater system, CRDS, FPCS, or GDCS is available. The ADS functions to reduce the RPV pressure. Heat removal by the ICs is not credited because of the low reactor pressure. Short-term CHR is accomplished by successful PCCS functioning; PCCS pool makeup is successful, thus allowing long-term CHR. The GDCS deluge system and BiMAC are available for debris bed cooling. With successful containment isolation, vapor suppression, and CHR, the containment remains intact. TSL is the only mode of fission product release.

In this event, the primary system experiences delayed depressurization because of the opening of the first ADS-actuated valves at about 621 seconds. The pressure in the containment increases as the drywell is filled with steam and heats up. The core becomes uncovered about 30 minutes into the event. The following occur after core uncover: fuel rod heatup and fission product release, hydrogen production from oxidation of the fuel cladding, and fuel melting. The fission products and hydrogen are swept into the containment through the DPVs as the core melts. This leads to further heating and pressurization of the drywell air space.

The RPV lower head penetrations fail about 7.5 hours into the event. Core debris is deposited on the LDW floor, leading to a temperature increase high enough to cause the GDCS deluge line to open. The GDCS pool water then drains into the LDW and covers the debris bed. The BiMAC functions as designed to quench the debris, preventing significant CCI. Therefore, no significant fission product aerosols or noncondensable gases are generated in the ex-vessel phase of the accident sequence.

The core debris in the LDW heats the water pool, generating steam that pressurizes the containment until the PCCS heat removal capacity becomes consistent and comparable to the decay heat generated by the core debris. The containment pressure reaches about 0.81 MPa (117 psi) 24 hours after the onset of core damage and before the time when containment venting would be implemented. Radionuclide release to the environment occurs only through potential containment leakage because the containment remains intact and venting is not required.

Sequence MLI_nCHR (Represents Class II)

The initiating event for the sequence MLI_nCHR is a medium LOCA, which is assumed to occur in the GDCS injection line. Failure of CHR is followed by containment pressurization to its ultimate capacity. Core cooling occurs by gravity feed through the GDCS injection and equalizing lines. Eventually, the water used for RPV makeup is boiled off.

The containment pressurizes until the ultimate strength is reached at about 33 hours. The ADS depressurizes the RPV, which allows GDCS tanks to drain into the RPV and then into the LDW through the break. The shroud water level initially rises in response to the GDCS tank injection, then decays as the GDCS inventory is depleted. The shroud level decreases below the elevation of the break at about 5.3 hours. Further shroud level decrease occurs until flow through the equalizing line begins at about 6.2 hours. Flow from the suppression pool maintains the RPV level above the top of active fuel (TAF) beyond 72 hours.

The results of the sequence simulation indicate that the core damage following containment failure as the result of loss of CHR does not occur within a 24-hour period after accident

initiation. In fact, core temperatures do not reach the point of fuel damage until more than 72 hours after accident initiation. Given the long time during which mitigating actions can be implemented to supplement RPV makeup, Class II events are not considered contributors to the offsite consequence analysis.

Sequence T_nDP_nIN_TSL (Represents Class III)

An LOPP is the initiating event for the sequence T_nDP_nIN. This sequence differs from T_nIN in that depressurization fails, although the SRVs remain functional in the relief mode. The ICS is not credited. The CRD and feedwater systems are unavailable. The RPV fails at about 5.9 hours, with the RPV at a pressure close to the SRV setpoint.

Actuation of the GDCS deluge line and successful BiMAC function prevent significant CCI from occurring in the LDW. Material dispersed to the UDW does not result in significant CCI because the large dispersal area allows the material to be cooled. Continued heating of the water by debris in the LDW leads to continued steam generation, which increases containment pressure. The PCCS removes heat from the containment, thus preventing overpressurization. The drywell pressure 24 hours after the onset of core damage is 0.86 MPa (125 psi).

For the case in which CHR has failed, the containment pressure increases, and controlled venting is implemented to limit the pressure rise and control the radiological releases. The drywell pressure reaches 1.01 MPa (146 psi) 24 hours after onset of core damage; thus, venting would not likely be implemented in this timeframe. The 90-percent assumption for venting initiation is met at approximately 28 hours after accident initiation, which is about 3.7 hours before containment failure caused by overpressurization would be expected.

Sequence T-AT_nIN_TSL (Represents Class IV)

Sequence T-AT_nIN is a general transient followed by an ATWS. The SLCS is ineffective or unavailable. The RPV is not initially depressurized because the ADS is successfully inhibited. To control the ATWS power level, feedwater runback is successful with operator control assumed at the TAF. The PCCS is available, but no active CHR (e.g., FAPCS) is assumed.

Control of core water level just above the TAF results in a core power level of about 30 percent of full power 3 minutes after the transient begins. At that time, it is assumed that feedwater is terminated and safety system injection to the RPV does not occur. (System pressure prevents gravity drain from the GDCS, and the CRDS is unavailable for forced flow.) Because the ADS inhibit is successful, the RPV is maintained at high pressure, controlled by the SRV setpoint, until the core water level decreases below the point of effective cooling. At that point, manual depressurization is initiated, but injection into the RPV continues to be unsuccessful. RPV failure occurs at about 5.9 hours at low pressure.

Actuation of the GDCS deluge lines and successful BiMAC function prevent significant CCI from occurring in the LDW (CCI is limited to the protective layer of concrete on top of BiMAC). The dispersed core debris to the UDW regions would not result in significant CCI because of the large cooling potential of the core debris when dispersed over a large area. Continued heating of water by the core debris in the LDW results in protracted generation of steam and containment pressurization. The PCCS condenses the debris-generated steam from the containment, thus preventing containment failure by overpressurization.

The containment pressure reaches about 0.81 MPa (117 psi) 24 hours after onset of core damage, well below the point at which containment venting would be implemented. Radiological releases to the environment occur only through potential containment leakage at the TSL limits because the containment remains intact and venting is not required.

For all of the representative sequences, the containment is intact at 24 hours, and no fission product releases have occurred by this time.

19.1.4.2.1.1.3 Release Category Definitions

The containment response to a severe accident is depicted by the end states of CETs. These end states become the release categories that are used to characterize potential source terms. The source terms are used in the offsite consequence analysis.

Each end state of the CET set is assigned to 1 of 11 containment release categories. Of the release categories, 10 are containment failure or bypass modes. If no containment failure or bypass occurs, the release associated with allowable TSL is assumed. Table 19.1-7 summarizes the release categories.

Table 19.1-7. Release Categories, End States, and Release Paths.

RELEASE CATEGORY	END-STATE DESCRIPTION	SIGNIFICANT FACTORS	RELEASE PATH
Break Outside Containment	Unisolated piping break occurs outside of containment.	Feedwater, main steam, RWCU/SDC line breaks	RPV to environment
BYP	Loss of isolation occurs.	CIS function failure	Drywell to environment
CCID	LDW corium debris not flooded; CCI noncondensable gas ruptures drywell.	Unsuccessful GDCS deluge	Drywell to environment
CCIW	LDW corium debris bed flooded but not effectively cooled; CCI gas ruptures drywell.	Unsuccessful GDCS deluge	Drywell to environment
DCH	DCH event (RPV failure at high pressure) overpressure ruptures drywell or fails liner.	physically unreasonable; no failure assumed	Drywell to environment
EVE	EVE at RPV failure ruptures drywell.	Gravity core drop into deep (> 1.5 m [>4.9 ft]) water pool	Drywell to environment
FR	Wetwell airspace vented before steam overpressure ruptures drywell.	Suppression pool vent opened by operator	Filtered through pool
OPVB	Vacuum breakers fail to close or are open; steam overpressure ruptures drywell.	Containment pressure suppression function fails	Drywell to environment

RELEASE CATEGORY	END-STATE DESCRIPTION	SIGNIFICANT FACTORS	RELEASE PATH
OPW1	CHR fails in first 24 hours; steam overpressure ruptures drywell.	PCCS or pool cooling system failure	Drywell to environment
OPW2	CHR fails after 24 hours; steam overpressure ruptures drywell.	PCCS unavailable after 24 hours	Drywell to environment
TSL	Leakage allowed from the drywell at the TSL (0.5 percent of containment air volume per day at rated pressure).	Preexisting small leak paths from drywell	Drywell to environment

19.1.4.2.1.1.4 ESBWR Conditional Containment Failure Probability

The CET quantification for internal events resulted in a cumulative containment failure frequency of 1.4×10^{-9} per reactor-year. The Level 1 CDF is 1.65×10^{-8} per reactor-year, so that the ESBWR CCFP for all non-TSL failure modes is 0.08 (the ratio of these two numbers), which is consistent with the NRC's containment performance objective of 0.10.

19.1.4.2.1.1.5 Source Term Evaluation

The applicant performed the source term evaluation using the MAAP 4.0.6 computer code, which produces the distribution of radionuclides released to the environment as a function of time. The source terms are input from the Level 2 PRA to the Level 3 consequence analyses.

Each release category is represented by one or two severe accident sequences selected and modeled to represent the group of potential severe accidents that could be associated with that release category. In some cases, both low-pressure and high-pressure classes were selected for the same release category to represent broader and more thorough contributions of accident sequences. For each source term, the timing, energy, isotopic content, and magnitude of release are established based on plant-specific T-H calculations using the MAAP 4.0.6 code.

The analysis typically incorporated conservative assumptions to account for analytical and phenomenological uncertainties.

The core loading inventory assumed in developing the source term is bounding for enrichment and exposure for GE14 fuel. It assumes an end-of-cycle equilibrium inventory, with a core average exposure of 36 gigawatts/metric ton of uranium (GW/MTU), a maximum discharge exposure of 58 gigawatt-days/metric ton of uranium (GWd/MTU), and a power density of 5.75 megawatt-thermal (MWt)/bundle. These values represent the expected ESBWR operating conditions.

In Section 9 of Revision 4 of the PRA report, GEH, in response to RAI 19.1-177, revised the source terms for release categories CCID, CCIW, FR, OPVB, OPW1, and OPW2 to account for the reduction in the containment ultimate capacity. The applicant provided two sets of release fractions: 24-hour and 72-hour release fractions. Consistent with the previous revisions, the release fraction at 24 hours represented early release source terms, and the release fraction at 72 hours represented release variations and uncertainties at least 24 hours up to 72 hours after the event.

19.1.4.2.1.2 Significant Accident Sequences and Accident Classes Contributing to Containment Failure

Most of the release categories listed in Table 19.1-7 are associated with overpressurizing the containment. Also included are preexisting small leak paths from the drywell (i.e., TSL), venting from the wetwell airspace in such a way as to enable fission product scrubbing by the suppression pool (i.e., FR), failure to isolate the containment (i.e., BYP), and an unisolated pipe (i.e., break outside containment).

Section 21 of the PRA discusses the potential for containment failure as the result of DCH, EVE, and BMP in the ROAAM evaluation. Section 9 of the PRA discusses containment overpressure failure as a consequence of system failures. The following sections briefly explain these failure modes, as pertinent to the ESBWR.

19.1.4.2.1.2.1 Containment Failure from Direct Containment Heating

DCH may occur when high-velocity steam impinges on melt already released into a containment compartment, which creates regions of fine-scale mixing, a large interfacial area for heat transfer, and oxidation of metallic components in the melt. In the ESBWR, the mixing occurs in the LDW, while the main receiving volume, in which deentrainment occurs, is in the UDW.

The ROAAM analysis demonstrated that the ESBWR containment can withstand bounding DCH pressure loads and concluded that catastrophic containment failure as the result of DCH is physically unreasonable.

The applicant stated that the following factors support this conclusion:

- The UDW atmosphere can vent into the wetwell through a large vent area and an effective heat sink.
- The drywell head is (externally) immersed in water and essentially isolated from the UDW atmosphere.
- The containment steel liner is structurally backed by reinforced concrete, which cannot be structurally challenged by DCH.

Therefore, the PRA does not identify DCH as a containment rupture failure mode.

However, the calculations also show short periods of potentially very high temperatures in the LDW atmosphere (up to 4,000 kelvin [K])(6,740.3 degrees F). These high temperatures and the presence of potentially large quantities of melt in the LDW indicated that the LDW liner could be subject to local failures. The applicant's position is that liner failure in the LDW space would not constitute containment failure because of the presence of structural "lips" that isolate the gap space from that of the upper portions of the containment wall. The staff considered the design of the lips and concludes that the applicant's assumption is reasonable.

19.1.4.2.1.2.2 Containment Failure and BiMAC Failure Resulting from Ex-Vessel Steam Explosions

EVEs are energetic FCIs that are triggered from melt-coolant mixtures that develop as the melt released from the RPV falls into and traverses the depth of a water pool below. Metallic melts,

such as those expected for low-pressure scenarios, are especially prone to energetic behavior. When large quantities of melt are involved with highly subcooled water, the result is pressure pulses that are potentially capable of loading major structures to failure.

The relevant structures are the reactor pedestal (a 2.5-m [8.2-ft] reinforced concrete wall) and the BiMAC device, a layer of thick-walled steel pipes that are well embedded in reinforced concrete in such a way that they are supported in all directions. Failure of the reactor pedestal, along with the steel liner on it, would constitute violation of the containment boundary. While the load-bearing capacity of this structure is 2.85 MPa (413 psi), explosive-level pressures acting on a time scale of milliseconds can produce concrete cracking, along with liner stretching and tearing, sufficient to compromise the leaktightness of the containment. Failure of the BiMAC device, on the other hand, is defined as crushing (or locally collapsing) the pipes so that they cannot perform their heat removal function of channeling the so-generated two-phase mixture from the bottom onto the top of the debris mass. Such failure would raise the possibility of continuing corium-concrete interactions, BMP, and containment pressurization by the so-generated noncondensable gases.

The ROAAM assessment in Chapter 21 of the PRA finds that failure of the ESBWR containment liner (and therefore, the leaktightness of the containment) because of EVE is physically unreasonable for shallow, saturated pools. For accidents involving deep (greater than 1.5 m [4.92 ft]), subcooled water pools, the PRA utilizes an appropriately conservative position that, because “integrity of both the liner and the concrete structure could be possibly compromised,” the containment will rupture at RPV failure from overpressure. A sensitivity study performed by the applicant shows that medium-depth pools are of negligible importance. On the other hand, the applicant argued that the BiMAC can resist higher dynamic loads than can the pedestal and the containment liner and therefore is not susceptible to failure as the result of EVE.

Analyses reported in Section 21 of the PRA support the conclusion that for all but 1 percent of the CDF (i.e., accidents involving deep, subcooled water pools), violation of the ESBWR containment leaktightness and the BiMAC function as the result of EVE is physically unreasonable. The applicant cites the following features to support this conclusion:

- An accident management strategy and related hardware features that prohibit large amounts of cold water from entering the LDW before RPV breach
- The physical fact that premixtures in saturated water pools become highly voided and thus unable to support the escalation of natural triggers to thermal detonations
- Reactor pedestal and BiMAC structural designs capable of resisting explosion load impulses of over about 500 kilopascal-seconds (kPa-s) (72.5 psi-s) and about 100 kPa-s (14.5 psi-s), respectively

A consequence of this analysis is that the ESBWR PRA assumes that an EVE adequate to fail containment occurs with a probability of 1.0 every time the core melts through the RPV and falls under gravity into an LDW with a “high” water level. The ROAAM assessment demonstrates that, if the water level is “medium” or “low/dry,” a sufficiently energetic steam explosion is physically unreasonable. PRA sensitivity studies assign a failure probability of 1.0×10^{-3} to cases involving a medium water level in the LDW.

19.1.4.2.1.2.3 Containment Failure from Molten Core-Concrete Interactions

Section 21 of the PRA states that the BiMAC device is effective in containing all potential core melt releases from the RPV in a manner that ensures long-term coolability and stabilization of the resulting debris. Neither significant ablation of concrete in the basemat or pedestal wall nor containment overpressurization by concrete decomposition gases would occur. The applicant stated that the following features support this conclusion:

- A layer of concrete will serve as a protective layer to eliminate impingement attack by superheated metallic jets.
- Proper positioning and dimensioning of the BiMAC pipes allow for stable, low-pressure-loss and natural circulation that is not susceptible to local burnout resulting from thermal loads exceeding the critical heat flux (CHF) or to dryouts resulting from flow- and water-deficient regimes.
- The BiMAC in the LDW can be sized and positioned in such a way that all melt released from the vessel (except any melt dispersed to the UDW in high-pressure scenarios) is captured and contained.
- The provision of an angle of inclination of the lower boundary can balance the various requirements, including operational space available and good margins to local burnout.

The applicant has assigned a nodal value of 2.7×10^{-4} (citing historical data) for failure of debris cooling due to BiMAC line plugging and failure of GDSC flow following successful deluge operation based on the design of the BiMAC device.

Accident sequences that successfully supply water to the BiMAC, but with the BiMAC non-functional, are terminated with the release category core-concrete interactions-wet (CCIW). The category assignment indicates that the corium debris bed is successfully covered with water, but CCI proceeds because of inadequate cooling to terminate the interactions. That is, the debris bed becomes relatively impermeable to water, or for some other reason, the overlying water pool does not prevent MCCI. Systems considered in the CET will not mitigate the containment pressure rise attributable to noncondensable gas generation, which will lead to eventual containment overpressurization failure.

Accident sequences in which no water is supplied to the BiMAC terminate with the end-state core-concrete interactions-dry (CCID). In such accident sequences, the CCI would be greater than the CCIW end state because there is no debris bed cooling. High levels of aerosols and noncondensable gases are produced and eventually lead to containment overpressurization failure.

In response to RAI 19.2-32, GEH provided the results of sensitivity studies using MAAP 4.0.6, which it performed to estimate concrete ablation for both limestone and basaltic concrete to assess the potential for RPV pedestal failure. These cases involved a loss of injection with successful depressurization of the RPV.

The thickness of the ESBWR LDW wall (RPV pedestal) is 2.5 m (8.2 ft), and the thickness of the ESBWR basemat is 5.1 m (16.7 ft). The BiMAC, which is 1.6 m (5.25 ft) thick, is located on top of the basemat. Breach of the pedestal would occur at an ablation depth of 2.5 m (8.2 ft), with a possible loss of structural integrity at a lesser depth.

The calculated times after RPV failure to horizontal ablation of 2.5 m (8.2 ft) ranged from 26 hours (dry LDW basaltic) to 55 hours (dry LDW limestone) to beyond the 72-hour run time (limestone and basaltic in flooded LDW). The staff's confirmatory assessment of CCI using MELCOR 1.8.6 confirms that concrete ablation depths in the axial direction would be of similar or somewhat smaller magnitude than those predicted by MAAP 4.0.6 for several comparable sequences involving assumed basaltic concrete under both dry and wet conditions. A representative MAAP 4.0.6 calculation for CCID in Appendix 9A to the PRA shows that the containment overpressure failure limit is reached at about 20 hours after RPV failure for a basaltic concrete basemat, well before pedestal failure would occur. While it is possible that a horizontal "blowout" may occur into the lower reactor building (RB) somewhat before the 20 hours, because of local thinning of the pressure boundary in the region of the BiMAC trough, further analysis of this event is of questionable value given the very low probability of a CCID-type event. It is reasonable to assume that the containment would fail from overpressurization before basemat melt-through or pedestal failure.

Assuming the successful operation of the deluge system, no credit for operation of the BiMAC, and the anticipated heat transfer to water above the debris pool, the expected response is ablation of less than half the pedestal thickness. The staff finds the applicant's response to RAI 19.2-32 reasonable, so the issue is resolved.

19.1.4.2.1.2.4 Containment Isolation System Failure

In these events, the failure of the CIS causes the containment to be bypassed. As a result, there is a direct path from the containment atmosphere to the environment from the start of the accident (i.e., BYP).

19.1.4.2.1.2.5 Containment Heat Removal Function Failure

This is the condition in which the vapor suppression capability has functioned, but there is a failure to remove heat from the containment. The containment fails by overpressurization from stored energy and decay heat. Short-term (defined as OPW1) and long-term (defined as OPW2) containment failure modes correspond to failures within 24 hours and after 24 hours of core damage, respectively.

19.1.4.2.1.2.6 Vacuum Breaker Failure

This is the condition in which a vacuum breaker is open or fails to reclose, thus defeating the vapor suppression function, which, in turn, also fails CHR. The containment fails by overpressurization, most likely sooner than in cases represented by OPW1 and OPW2.

19.1.4.2.1.2.7 Containment Venting

The ESBWR contains a manually initiated vent connecting the suppression chamber gas space to the environment. Venting is potentially effective only in the case of CHR function failure and would serve to convert the uncontrolled overpressurization containment failure into a controlled venting path from the drywell atmosphere through the suppression pool into the environment (i.e., containment venting, referred to as FR). Forcing the radionuclide pathway to go through the suppression pool effects a filtering action. The expected operator guidance is to open the vent lines as needed to limit the pressure rise to be below 90 percent of the containment ultimate pressure capacity.

19.1.4.2.1.2.8 Break Outside of Containment

In this event, a piping break outside containment occurs in which the RPV communicates directly with the environment. A representative event is a reactor water cleanup (RWCU) large-line break above the core, which represents a potential path from the RPV directly to the environment and a large source term.

In response to RAI 19.2-38, the applicant discussed the possible failure of an ICS tube. The analysis of a break outside containment in the ICS, as an initiator, shows that the break makes a negligible contribution to the CDF. Therefore, RAI 19.2-38 is resolved.

Containment bypass because of an IC tube failure is not probable. A temperature-induced IC tube failure requires that the level in the IC pool be lowered as the result of boiling that uncovers the IC heat exchanger. The IC heat exchanger is designed to withstand the design temperature and pressure of the RPV. The IC heat exchanger will not see higher pressures without multiple failures of SRVs to control RPV pressure. Temperatures above the design temperature require that the core is first uncovered, as steam exiting the core would be at saturation temperature.

Water hammer is not probable as the IC heat exchangers are normally pressurized because of the open steam supply valves. Condensate fills the piping from the IC heat exchanger to the condensate return valves. A loop seal between the condensate return valves and the RPV is designed to ensure that steam continues to enter the IC heat exchanger preferentially through the steam riser, irrespective of the water level inside the reactor, and does not move counter-current back up the condensate return line.

The RWCU break outside containment analyzed in the PRA bounds the consequences of an IC tube failure. The RWCU sequence is an unisolated break outside containment in the SDC piping followed by no injection into the RPV. In this scenario, the release begins at the onset of fuel damage and proceeds directly to the environment.

The release in the IC tube failure sequence would occur after fuel damage, as heatup of the uncovered IC heat exchanger is required. This sequence is a Class III sequence (core damage with the RPV at high pressure) and also requires a failure to isolate the lines.

19.1.4.2.1.2.9 Technical Specification Leakage

The TS limit for allowable containment leakage is 0.35 percent of containment air volume per day at rated design-basis pressure. A more conservative assumption of 0.5 percent, which is included in all of the modeled severe accident sequences, represents the no containment failure/bypass outcome. The leakage path is conservatively assumed to occur directly between the drywell atmosphere and environment, thus bypassing the suppression pool and the RB heating, ventilation, and air conditioning (HVAC) system mitigation pathways.

19.1.4.2.1.3 *Leading Contributors to Containment Failure from Level 2 Internal Events Probabilistic Risk Assessment*

Table 19.1-8 provides the list of release categories and their contributions to containment failure (CF). This table also shows representative cesium iodide (CsI) release fractions at 24 hours after core melt. The break outside containment frequency is directly calculated from failures of containment isolation for pipes that break outside containment in the Level 1 PRA. In addition, since on the average the containment would be deinerted for a period of 24 hours per year, and

deflagration due to presence of combustible gases cannot be excluded when the containment atmosphere is deinerted, GEH conservatively assumed that all core damage events during the deinerting period would lead to containment failure. The applicant calculated this contribution as 4.52×10^{-11} per reactor-year (i.e., CDF/365) and added it to the BYP frequency.

Table 19.1-8. Release Category Frequencies and Representative Release Fractions.

RELEASE CATEGORY	FREQUENCY (PER REACTOR-YEAR) (% CONTRIBUTION TO CF)	REPRESENTATIVE CSI RELEASE FRACTION AT 24 HOURS
TSL (no CF)	1.51×10^{-8} (0)	0.00016
EVE	1.14×10^{-9} (83)	0.028
Break Outside Containment	8.50×10^{-11} (6.2)	0.70
CCIW	2.93×10^{-12} (0.2)	0.00015
BYP	5.77×10^{-11} (4.2)	0.21
OPW1	1.96×10^{-12} (0.1)	0.0
OPVB	1.97×10^{-12} (0.1)	0.0033
CCID	1.48×10^{-12} (0.1)	0.068
FR	7.68×10^{-11} (5.6)	0.0
OPW2	5.64×10^{-12} (0.4)	0.0
DCH	0	-

The quantification resulted in a summed (all release categories except for TSL in Table 19.1-8) containment failure frequency of 1.4×10^{-9} per reactor-year. These are all termed “large releases.”

The low-pressure Class I accident sequences contribute the majority (83 percent) of the containment failures, almost entirely in the release category EVE. The necessary and sufficient condition for an EVE is a low-pressure RPV breach at a time when the LDW water depth is more than 1.5 m (4.92 ft). The dominant Level 1 sequence meeting this condition is a large LOCA with pressure suppression success and failure to inject.

Class II contributes 2 percent of the containment failures, mostly as the release category FR.

The high-pressure Class III contributes about 0.4 percent of the containment failures, mostly as the release category BYP.

Class IV (ATWS type) contributes 5 percent to the CFP, mostly as the release categories BYP and EVE.

Class V contributes 6 percent to the containment failure probability (CFP) entirely as the release category (break outside containment).

Section 10 of Revision 6 of the PRA report provides release category frequencies for the external (internal fire, internal flood, and high winds) and shutdown events. For the external events during power operation, core damage sequences were assigned to various accident classes and release categories using an approach similar to that used for the internal events. For the external events during shutdown, the analyses conservatively assumed that the core damage scenarios result in large releases because the containment is open during most of the shutdown period.

19.1.4.2.1.4 *Risk-Significant Equipment/Functions/Design Features, Phenomena/Challenges, and Human Actions*

The following paragraphs summarize important insights from the Level 2 PRA. These insights are organized in terms of equipment and design features, severe accident phenomena and challenges, and human actions.

The analysis evaluated the potential for at-power internal events containment failure as the result of combustible gas generation, containment bypass, and overpressurization. In addition, the analysis determined the frequency of containment failure events resulting from the phenomenological events discussed in Section 21 of the PRA (CCI, DCH, and EVE).

Because of the ESBWR design and reliability of containment systems, the most likely containment response to a severe accident is associated with successful containment isolation, successful vapor suppression, and successful CHR. As a result, the containment provides a highly reliable barrier to the release of fission products after a severe accident, with only 8 percent of the core damage accidents resulting in releases larger than those associated with the minimal release leakage at the TS limit. This result meets the Commission's recommended goal of 10 percent for CCFP.

A containment penetration screening evaluation indicated that only a few penetrations required isolation to prevent significant offsite consequences. The probability of the bypass failure mode is dominated by common-cause hardware failures, resulting in a calculated frequency of containment bypass about three orders of magnitude lower than the TSL release category.

19.1.4.2.1.4.1 Equipment/Design Features

The ESBWR features an inert containment atmosphere to prevent deflagration or detonation of combustible mixtures and a manually operated containment overpressurization protection system to guard against slow buildup of pressure resulting from noncondensable gas generation or heatup or both of the suppression pool water. Unlike the advanced boiling-water reactor (ABWR), or any other previous GEH BWR, the ESBWR containment design includes the PCCS to remove decay heat from the containment and the passive BiMAC device, which is intended to essentially eliminate the possibility of extended core-concrete interactions, noncondensable gas generation, and BMP. The containment has a high ultimate rupture strength and special liner mounting features. Fire water injection can be utilized to arrest core melt progression in-vessel, but this capability was not modeled in the PRA.

Table 19.1-9 of this report summarizes the containment challenges and mitigative attributes in place for the ESBWR. These attributes have contributed to reducing or eliminating the likelihood of the associated severe accident challenges in the ESBWR.

Table 19.1-9. Summary of Containment Challenges and Mitigative Attributes in Place.

CHALLENGE	FAILURE MODE	MITIGATION
DCH	Energetic Drywell Failure	Pressure Suppression Vents Reinforced Concrete Support
	UDW Liner Thermal Failure	Liner Anchoring System
	LDW Liner Thermal Failure	Reinforced Concrete Barrier Cap Separation from UDW
EVE	Pedestal/Liner Failure	Dimensions and Reinforcement
	BiMAC Failure	Pipe Size and Thickness Pipes Embedded in Concrete
BMP and CCI	BiMAC Activation Failure	Sensing and Actuation Instrumentation Diverse/Passive Valve Action
	Local Melt-Through	

19.1.4.2.1.4.2 Phenomena and Challenges

Given a severe accident, the applicant has considered the following challenges to containment integrity:

- Prompt, energetic loading—explosive FCIs, HPME leading to DCH (and pressurization)
- Late, gradual loading—melt ablation and penetration of the containment basemat, pressurization of containment atmosphere by steam or noncondensable gases or both
- Isolation failure—errors or malfunctions that leave existing flowpaths open to the outside, activation of the containment overpressure protection system

Section 21 of the PRA report discusses the phenomenological (physics) components of these threats (namely, EVE, DCH, and BMP) as part of the ROAAM process. The discussion of BMP also provides the principal phenomenological input needed to assess containment overpressurization, which, because it is a systems-driven event, the Level 2 PRA treats. This is the case for isolation failure as well.

The applicant's ROAAM process found that for all but a very low fraction of the CDF (i.e., accidents involving deep, subcooled water pools) violation of the ESBWR containment leak-tightness and the BiMAC function as the result of EVE is physically unreasonable. The process

also determined that the ESBWR containment can withstand bounding DCH pressure loads and that catastrophic containment failure as the result of DCH is physically unreasonable. The staff concurs with this determination.

The applicant also found that the BiMAC device is effective in containing all potential core melt releases from the RPV in a manner that ensures long-term coolability and stabilization of the resulting debris. The mode and location of lower head failure is treated as a splinter set of scenarios. A high/side failure (i.e., at some elevation above the very bottom of the RPV) would make all events bounded by the ROAAM analysis because the quantities and rates of melt location from the RPV into the LDW would be significantly lower. In particular, this phenomenon would tend to eliminate the DCH and steam explosion threats and would make all BiMAC-related performance even more reliable.

External events and shutdowns do not impact the accident progression or source term magnitude. They may, however, lead to failures of support systems. External event severe accidents have no direct impact on the probability of containment failure. Shutdown event analyses conservatively assume that these core damage scenarios result in large releases since the containment is open during most of the shutdown.

19.1.4.2.1.4.3 Human Actions

Because of the passive nature of the ESBWR containment systems, no operator actions are required to support the containment response to a severe accident in the 24-hour period after onset of core damage.

The CIS, vacuum breakers, and PCCS do not require operator action to initiate or function. Operator action is not required to maintain CHR through the PCCS for the 24-hour period after onset of core damage, and containment venting will not be required during that period.

Therefore, the containment evaluation considers operator actions only in the following cases:

- Action is taken as a backup to an automatic action (e.g., to open the connecting valve for PCCS pool makeup if the low-water-level signals were to fail).
- Action is taken to initiate a backup system (e.g., to actuate the FAPCS if the PCCS were unavailable).
- Actions require a long time to initiate. For example, the suppression chamber vent is under operator control. In virtually all scenarios, a long period (more than 24 hours) would be necessary to initiate venting to prevent containment overpressure resulting from a loss of CHR. In fact, manual actuation is desirable because the time for venting can be based on plant, weather, and evacuation information available to the operators.

Because these operator actions are redundant to passive system functions or are required only after a long time, such actions do not have a significant impact on the probability of containment failure.

19.1.4.2.1.5 *Insights from Uncertainty, Importance, and Sensitivity Analyses.*

19.1.4.2.1.5.1 Uncertainty Analysis

GEH does not consider a formal uncertainty analysis to be necessary for the Level 2 portion of the ESBWR PRA because of the bounding nature of the ROAAM process for developing the CET split fractions. In these cases, the high confidence values are used rather than the mean values. The staff agrees with this approach.

Severe accident phenomena are complex, and the details of many processes are not fully understood. One feature of the ROAAM approach is its attempt to identify areas of uncertainty, while making best use of current understanding (supplemented by experimental and analytical efforts) to allow issue closure without the need to address all details of all processes (e.g., those leading to the spontaneous triggering of a steam explosion).

The applicant acknowledges that, in ROAAM, when the basis of evaluation is epistemic, probabilities are subjective. Therefore, a numerical probability scale can be used only for the purpose of propagating uncertainties. This approach was used in all previous applications of ROAAM (as enumerated in Section 21.2 of the PRA), and the staff finds such a qualitative interpretation of the end results to be appropriate and sufficient. Application of this procedure to the ESBWR is simpler than previous applications, and the results are more robust in two ways. First, for all potential containment challenges, strongly bounding arguments can be made at a level of generality and margins that obviate the need for propagation of uncertainties. Second, according to the ROAAM “quality of evaluation criteria” (see Table 21.6-2 in the PRA), all assessments can be made independently of scenario details.

Uncertainties remain in the Level 2 PRA even given the bounding nature of the ROAAM process. Though numerical nodal failure values (branch probabilities) were assigned (typically a value of 1×10^{-3} is assigned for phenomena), the applicant did not analyze source term uncertainties in terms of time, quantity, and chemical and physical forms of release. The ROAAM process does not cover the systems portions of the CETs, and it does not consider the propagation of the driving Level 1 PRA numbers. The Level 2 uncertainty analysis presented in Section 11 of the PRA demonstrates that the ratio of the upper bound of the LRF (95th - percentile) to the mean value is approximately 3. Nevertheless, the bounding nature of the ROAAM process, coupled with the very low levels of CDF, containment failure probability (CFP), and the absolute risk of core damage and fission product release, as well as a large number of sensitivity studies, is such that uncertainty analyses for the Level 2 PRA would not produce additional insights.

19.1.4.2.1.5.2 Importance Analysis

GEH does not report results of any importance analysis for the Level 2 PRA. Because the ROAAM approach is bounding in nature, the staff agrees that an importance analysis is not required.

19.1.4.2.1.5.3 Sensitivity Analysis

Tables 11.3-18, 11.3-18A, 11.3-19, and 11.3-19A of Section 11 of the PRA report, Revision 6, provide the results of four Level 2 sensitivity studies, which are summarized below. Level 3 studies, discussed in Section 19.1.4.3.5 below, address the sensitivity of offsite consequences

to meteorological conditions, release elevation, release energy (heat and buoyancy), and mission time.

The Level 2 PRA generally utilizes the metric “non-TSL” (nTSL) release as the equivalent of CDF in the Level 1 model; nTSL is assumed to be equivalent to the LRF.

19.1.4.2.1.5.3.1 *Containment Isolation System Node Placement in the Containment Event Tree*

In Revision 2 of the PRA report, the applicant described a Level 2 PRA model sensitivity analysis used to study the effect of moving the CIS node to the first position in the event trees and to assess the impact on LRF. The current Level 2 PRA model is based on event trees with the CIS in a nodal position of three or four.

Results for the CIS node sensitivity analysis showed no impact on LRF as demonstrated by a lack of change in nTSL frequency over the PRA Level 2 base model. Consequently, the placement of the CIS node earlier in the event trees has little impact on the nTSL frequencies.

19.1.4.2.1.5.3.2 *Physically Unreasonable Phenomenology*

The current Level 2 PRA model contains containment failure modes that are considered physically unreasonable. The applicant performed a sensitivity study to better understand the impact to nTSL and source terms pertaining to the omission of these physically unreasonable modes from the model. These modes include EVE from a medium LDW water level and DCH.

Results for the sensitivity analysis of physically unreasonable failure modes in Revision 2 of the PRA report showed only a small increase in the nTSL frequency over the PRA Level 2 base model. A release frequency for DCH of 2.56×10^{-12} per reactor-year was obtained for the physically unreasonable modes contributing 0.2 percent to the total nTSL release frequency. The non-DCH release category source terms were minimally affected by the increased leakage area in their respective sequences. The DCH release category itself has a high release fraction, but its low frequency renders potential offsite consequences negligible. The analysis of the physically unreasonable modes confirms that the exclusion of physically unreasonable events from the Level 2 PRA model does not negate any potentially significant offsite consequences.

19.1.4.2.1.5.3.3 *Vacuum Breakers Data*

In the vacuum breaker sensitivity analysis, the applicant increased the failure rates of the vacuum breakers by a factor of 10 in the database file to account for uncertainty in general reliability and the anticipated number of cycles in the mission time.

Results for the vacuum breaker sensitivity showed an nTSL frequency of 2.06×10^{-9} per reactor-year at a truncation of 1×10^{-15} per reactor-year. This value for nTSL represents an increase in nTSL frequency of about 50 percent more than that of the base Level 2 model. However, the increased nTSL meets the NRC goal of 1×10^{-6} per reactor-year for LRF with considerable margin. The results show that the uncertainties associated with the primary vacuum breaker design and the anticipated number of cycles increase the LRF only slightly.

19.1.4.2.1.5.3.4 Squib Valves

In the squib valves sensitivity analysis, the applicant increased the failure rates of the squib valves by a factor of 10 in the database file to account for uncertainty in general reliability and the mission time.

Results for the squib valve sensitivity showed an nTSL frequency of 1.18×10^{-8} per reactor-year at a truncation of 1×10^{-15} per reactor-year. This value for nTSL represents an increase in nTSL frequency of almost one order of magnitude compared to the base Level 2 PRA model. However, the increased nTSL meets the NRC goal of 1×10^{-6} per reactor-year for LRF with considerable margin. Based on these results, the uncertainties associated with the squib valve reliability may contribute to slightly increased LRF, but the increase is reasonable.

19.1.4.2.1.5.3.5 BiMAC Failure

Given failure of the BiMAC and continued corium-concrete interaction, there is a potential for RPV pedestal failure. The applicant performed sensitivity studies using MAAP 4.0.6 to estimate concrete ablation for both limestone and basaltic concrete. These cases involved a loss of injection with successful depressurization of the RPV. Section 19.1.4.2.1.2.3 of this report discusses the results.

The applicant does not consider it useful to perform LRF-based sensitivities for operator actions for two reasons. First, because the total CDF estimated in this sensitivity is less than 1.0×10^{-6} per reactor-year, it is not possible to raise the LRF value above the goal. Second, the LRF evaluation credits no important operator actions. For example, removing the containment vent from the LRF calculation would not affect the results because both the success of the vent and the failure of containment as a result of overpressure are treated as large releases.

19.1.4.2.2 Regulatory Criteria

The staff has considered the results and insights from the Level 2 PRA with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report. The following five objectives for the applicant's use of the design PRA are especially relevant to the evaluation of results and insights from the Level 2 PRA:

- (1) Reduce or eliminate the significant risk contributors of existing operating plants that are applicable to the new design by introducing appropriate features and requirements.
- (2) Identify risk-informed safety insights based on systematic evaluations of the risk associated with the design such that the applicant can identify and describe the design's robustness, levels of defense-in-depth, and tolerance of severe accidents initiated by internal events.
- (3) Determine how the risk associated with the design compares against the Commission's goal of less than 1×10^{-6} /yr for LRF. In addition, compare the design against the Commission's approved use of a CPG, which includes (a) a deterministic goal that containment integrity be maintained for approximately 24 hours following the onset of core damage for the more likely severe accident challenges and (b) a probabilistic goal that the CCFP be less than approximately 0.1 for the composite of all core damage sequences assessed in the PRA.

- (4) Assess the balance between features of the design that prevent and mitigate accidents.
- (5) Determine whether the plant design represents a reduction in risk compared to existing operating plants.

19.1.4.2.3 Staff Evaluation

NUREG-1560 represents an extensive compilation of the results generated by the industry in performing its IPEs for the current generation of plants. The staff's observations on BWR containment performance include the following:

- The large-volume containments of PWRs are, on average, less likely to experience early structural failures than the smaller BWR pressure suppression containments.
- Overpressure failures, primarily from ATWS, FCI, and failures resulting from direct impingement of core debris are important contributors to early failure for most BWR containments; hydrogen burns are important in some Mark III containments.
- The higher probability of early structural failures of BWR Mark I plants, compared to the later BWR containments, is driven largely by drywell shell melt-through.
- Bypass is generally not important for BWRs.
- Overpressurization when CHR is lost is the primary cause of late failure in most PWR and some BWR containments.
- High-pressure and temperature loads caused by CCIs are important for late failure in BWR containments.
- Some Mark I IPEs have found that containment venting is important for avoiding late uncontrolled failure.

The staff's review of ESBWR DCD Tier 2, Revision 9, Chapter 19 and Sections 8-11 and 21 of the PRA report verifies that the ESBWR design is more robust and has greater tolerance for severe accidents than that of the operating plants. Specific findings include the following:

- The LRF for internal events is calculated by the applicant to be 1.4×10^{-9} per reactor-year, and the corresponding CCFP is calculated to be 0.08 (0.11 when external events are included). The LRF is about three orders of magnitude below the Commission's safety goal, and the CCFP is acceptably low. This is a significant reduction in risk as compared to existing BWRs, which typically have LRF values in the range of 1.0×10^{-6} per reactor-year to 1.0×10^{-5} per reactor-year and CCFPs up to 0.7, with an average value around 0.3.
- The design features and requirements introduced by the applicant reduce or eliminate significant risk contributors identified in existing operating plants. These features provide a good balance between prevention and mitigation for the following reasons.
 - The new features designed to prevent or mitigate ATWS greatly reduce the probability and consequences of ATWS and hence LRF.
 - Designing all piping systems, pumps, valves, and subsystems connected to the RCPB to an ultimate strength equal to or greater than the full RCPB pressure is a preventive

measure that reduces the likelihood of ISLOCA and consequent containment bypass probability and hence LRF.

- Since the ESBWR containment is designed to a higher ultimate pressure than that of currently operating BWRs, there is a higher likelihood of averting containment failure and hence a reduction in LRF and CCFP. The containment would be more likely to survive for at least 24 hours following the onset of core damage.
- A highly reliable ADS reduces the probability of a high-pressure core melt. This system plays a role both in preventing and mitigating severe accidents. It reduces the likelihood of early containment failure from DCH. Moreover, drywell segregation into upper and lower regions, and the ability to vent the UDW atmosphere into the wetwell through a large venting area, would mitigate the effects of a high-pressure core melt. Consequently, the risk impacts of high-pressure core melt events (LRF and CCFP) are reduced in comparison to those of current-generation BWRs.
- The deluge mode of GDCS operation, in concert with the BiMAC device, would act to further reduce the likelihood of containment failure, either from overpressurization, drywell liner melt-through, or BMP from core debris attack. Moreover, the design procedure of not immediately adding water greatly reduces the probability of a highly energetic steam explosion. Consequently, LRF and CCFP are further reduced relative to current-generation BWRs.
- The wetwell vent is available to avert catastrophic containment failure. It would not be needed during the first 24 hours after core damage and would be opened only if the containment pressure exceeded 90 percent of its ultimate capacity.

The NRC carried out an independent assessment of the ESBWR design response to selected severe accident scenarios using the latest version of the MELCOR 1.8.6 computer code. The assessment examined 13 accident scenarios from the ESBWR PRA, which were chosen based on a combination of frequency, consequence, and dominant risk. The majority of these scenarios were similar or identical to sequences analyzed with MAAP 4.0.6 by GEH in Revisions 1 and 2 of the PRA, and the assessment compared the results of corresponding sequences and release categories in the two studies. The results generally support and confirm the PRA accident progression analysis methodology and the GEH interpretations of its analyses of the ESBWR reactor, containment, and system response to severe accidents. With respect to the predicted radiological source terms, differences were observed for some release categories and fission product classes between the MELCOR 1.8.6 and MAAP 4.0.6 results, particularly for FR and late containment overpressure (OPW2). However, these two release categories are minor contributors to the ESBWR overall severe accident risk as determined by the PRA. For most release categories and fission product classes, the MELCOR 1.8.6 and MAAP 4.0.6 results either closely agree or differ by an amount that is within the margin attributable to fission product transport and other modeling uncertainties and to possible differences in scenario boundary conditions. Therefore, in the area of radiological release, the independent assessment using MELCOR 1.8.6 generally supports the results and conclusions of the source term analysis conducted in the ESBWR PRA.

19.1.4.2.4 Conclusion

The staff has reviewed the results and insights derived from the Level 2 PRA and sensitivity studies. Based on this review, the staff concludes that the applicant has performed adequate systematic evaluations of the risk associated with the design and used them to identify risk-informed safety insights in a manner consistent with the Commission's stated goals.

19.1.4.3 Results and Insights from Level 3 Internal Events Probabilistic Risk Assessment

The applicant performed a Level 3 PRA to assess the calculated ESBWR public risk level results to three major offsite consequence-related goals. These goals were established in the GEH ESBWR licensing review, and are based on the NRC Safety Goal Policy Statement.

The intent of the following implemented design goals is to ensure that the radiological risk from accidents in the ESBWR is maintained as low as reasonably achievable:

(1) Individual Risk Goal

NRC: The risk to an average individual, within 1.6 kilometers (km) (1 mile [mi.]) of the plant site boundary, of prompt fatalities that might result from reactor accidents should not exceed 0.1 percent of the sum of “prompt fatality risks” resulting from other accidents to which members of the U.S. population are generally exposed. For this evaluation, the sum of prompt fatality risks is taken as the U.S. accidental death risk value of 39.1 deaths per 100,000 people per year (3.9×10^{-4} fatalities per year).

GEH: As a design objective, the individual risk goal is set to be 3.9×10^{-7} fatalities per year within 1.6 km (1 mi.).

(2) Societal Risk Goal

NRC: The risk to the population, in the area within 16.1 km (10 mi.) of a nuclear power plant, of cancer fatalities that might result from nuclear power plant operation should not exceed 0.1 percent of the sum of the “cancer fatality risks” resulting from all other causes. The cancer fatality risk is taken as 169 deaths per 100,000 people per year (1.7×10^{-3} fatalities per year).

GEH: As a design objective, the societal risk goal is set to be 1.7×10^{-6} fatalities per year within 16.1 km (10 mi.).

(3) Radiation Dose Goal

NRC: The probability of exceeding a whole body dose of 0.25 sievert (Sv) (25 Roentgen man equivalent [rem]) at a distance of 805 m (0.5 mi.) from the reactor shall be less than 1.0×10^{-6} per reactor-year.

GEH: The design objective for the probability of receiving 0.25 Sv (25 rem) at 805 m (0.5 mi.) is set at less than 1.0×10^{-6} per reactor-year.

The staff agrees that these constitute a reasonable set of goals for establishing the level of public risk for the ESBWR, which are consistent with the NRC Safety Goal Policy Statement.

19.1.4.3.1 Level 3 Probabilistic Risk Assessment Methodology

The Level 3 PRA defined risk in terms of person-rem and calculated it by multiplying the yearly frequency of an event by its consequences. The consequences were defined as the committed effective dose equivalent (50-year committed) to the total population within a 16-km (10-mi.) and an 80.5-km (50-mi.) radius of the plant. The applicant used the MELCOR Accident

Consequence Code System (MACCS2), Version 1.13, to estimate accident consequences. The MACCS2 code evaluates offsite dose and consequences, such as early fatality risk and latent cancer fatality risk, for each source term (i.e., radionuclide release category) over a range of possible weather conditions and evacuation assumptions. The calculated results are compared to consequence-related goals to determine if the goals are satisfied. The analysis estimated effective doses for each of 10 different release categories.

For the ESBWR Level 3 PRA, each of the 10 nonzero frequency release categories is represented by one or two severe accident sequences that were selected and modeled to represent the group of potential severe accidents that could be associated with that release category. In some cases, both low-pressure and high-pressure classes were selected for the same release category to represent a broader and more thorough contribution of accident sequences. For each source term, the timing, energy, isotopic content, and magnitude of release were established based on plant-specific, T-H calculations using the MAAP 4.0.6 code.

Section 10 of Revision 6 of the PRA report lists the following input assumptions. The analysis used a meteorological condition comparable to the EPRI ALWR Utility Requirements Document (URD), Revision 4 meteorological reference data set. The Sandia siting study (NUREG/CR-2239, "Technical Guidance for Siting Criteria Development") population density data were used to develop a uniform population density. A bounding uniform density of 305 people per square kilometer (km^2) (790 people per square mile [mi.^2]) for the first 32 km (20 mi.) was used for all radial intervals. The evacuation parameters used in this analysis are termed conservative assumptions in that no evacuation or relocation in terms of physical movement was assumed and no sheltering was assumed. The public was assumed to continue normal activity during the reactor accident in this bounding analysis.

The analysis modeled the following two baseline cases:

- (1) The release category with 24-hour source terms was modeled to occur at ground level. The thermal content of the plume was assumed to be the same as ambient.
- (2) The release category with 72-hour source terms was modeled to occur at elevated level. The thermal content of the plume was assumed to have a buoyant energy of 1 megawatt.

The staff reviewed these analyses and finds the overall approach to consequence analysis and the use of the MACCS2 code to be consistent with the present state of knowledge regarding severe accident modeling and is therefore acceptable.

19.1.4.3.1.1 Results

In Section 10 of Revision 6 of the PRA report, the applicant provided risk and consequence results in terms of the safety goals for external events and shutdown modes, in response to RAI 19.1-13 S01. Table 19.1-10 of this report summarizes the baseline results for internal events and external events (i.e., internal fire, internal flood, and high winds) occurring during full-power operation and shutdown conditions and compares them to the evaluated NRC safety goals.

Table 19.1-10. Baseline Consequence Goals and Results
(from Revision 6 of the PRA Report, Table 10.4-2).

OPERATING STATUS AND RELEASE CONDITIONS		RISK GOALS CRITERIA AND RESULTS			
		INDIVIDUAL RISK 0–1.6 km (0–1 mi.) $< 3.9 \times 10^{-7}$ (0.1%)	SOCIETAL RISK 0–16 km (0–10 mi.) $< 1.7 \times 10^{-6}$ (0.1%)	RADIATION DOSE PROBABILITY > 0.20 SV (20 rem) at 0.8 km (0.5 mi.) $< 10^{-6}$	SAFETY GOAL ACHIEVED
At-Power Internal	C 1 ^a	1.6×10^{-10}	2.0×10^{-11}	2.0×10^{-9}	Yes
	C 2	1.6×10^{-10}	2.6×10^{-11}	1.9×10^{-9}	Yes
Shutdown Internal	C 1	3.9×10^{-9}	1.4×10^{-9}	3.4×10^{-8}	Yes
	C 2	3.7×10^{-9}	1.6×10^{-9}	3.4×10^{-8}	Yes
At-Power Fire	C 1	2.9×10^{-10}	1.0×10^{-10}	3.0×10^{-9}	Yes
	C 2	2.8×10^{-10}	1.2×10^{-10}	3.1×10^{-9}	Yes
Shutdown Fire	C 1	2.2×10^{-9}	8.0×10^{-10}	1.9×10^{-8}	Yes
	C 2	2.1×10^{-9}	8.9×10^{-10}	1.9×10^{-8}	Yes
At-Power High Wind	C 1	2.3×10^{-10}	8.4×10^{-11}	2.3×10^{-9}	Yes
	C 2	2.4×10^{-10}	9.4×10^{-11}	2.5×10^{-9}	Yes
Shutdown High Wind	C 1	9.1×10^{-9}	3.3×10^{-9}	7.9×10^{-8}	Yes
	C 2	8.5×10^{-9}	3.7×10^{-9}	7.9×10^{-8}	Yes
At-Power Flood	C 1	6.7×10^{-10}	2.4×10^{-10}	5.9×10^{-9}	Yes
	C 2	7.1×10^{-10}	2.8×10^{-10}	7.0×10^{-9}	Yes
Shutdown Flood	C 1	1.2×10^{-9}	4.4×10^{-10}	1.0×10^{-8}	Yes
	C 2	1.1×10^{-9}	4.8×10^{-10}	1.0×10^{-8}	Yes

a. C1 = Base Case 1 (ground release); C2 = Base Case 2 (elevated release).

Sections 19.1.5 and 19.1.6 of this report list external event and shutdown CDF and LRF results. The values listed are of the same magnitude as those for the at-power internal events case. Risk and consequence results in terms of the safety goals are not available for seismic events at power and shutdowns. Seismic events are not expected to add to the risk significantly, based on the seismic margin study results. Because the individual CDF values are developed with differing levels of conservatism, the applicant indicated that it is not meaningful to add CDF or LRF values to create total values. Nevertheless, it is apparent that for these two safety goal surrogate measures, the total risk for all PRA modes would not increase by more than two orders of magnitude.

GEH affirms that the individual risk and societal risk goals are maintained with sufficient margin, as shown in the preceding table. These results, together with supporting sensitivity studies, lead to the risk insight that the ESBWR design is protective of the public health and safety, as shown by the PRA analysis.

The staff finds the GEH public health and safety maintenance assertions in the ESBWR PRA to be sound. The staff agrees that the PRA risk and consequence results are consistent with the Commission's safety goals for individual risk, societal risk, and radiation dose, as well as the Commission's CPG.

19.1.4.3.1.2 *Insights*

Insights from the reported ESBWR Level 3 PRA results are summarized below:

- The estimated total risk to the public for the ESBWR design is low and acceptable. Offsite risk is very low compared to that of the current generation of operating plants because of a combination of (1) a very low estimated CDF, (2) a low CCFP, and (3) a relatively low source term associated with the frequency-dominant release category.
- The risk results demonstrate that the ESBWR, for accidents arising from internal events during full-power operation, meets the established consequence-related goals with substantial margin.
- The results for the ESBWR do not explicitly include the contribution to risk from external events. The surrogate risk results for externally initiated events and shutdown operations give confidence that the ESBWR would still meet the Commission's safety goal policy with margin when these additional contributors are included.
- The release category associated with normal containment leakage levels is a low but not negligible contributor to the public risk. It is assigned to every core damage accident.
- The containment failure accident release categories contributing most to the public risk (EVE, break outside containment, and BYP) have conditional probabilities of occurrence of 0.07 or less. For EVE, this results primarily from the design-driven low probability of high levels of water being present in the LDW just before vessel failure; for breaks outside of containment, from designing to the extent practical all components connected to the RCPB to an ultimate rupture strength at least equal to the full RCPB pressure; and for BYP, from the minimization of the number of penetrations.
- The other containment failure accident release categories contributing to the public risk have conditional probabilities of occurrence of 0.01 or less. These low probabilities are largely attributable to the presence of the BiMAC device.
- The applicant has chosen to designate all containment failures as large releases (i.e., those in excess of technical specification leakage). The staff finds this conservative assumption acceptable.

Based on its review of the DCD Tier 2, Revision 9, Chapter 19, the staff concludes that the applicant has identified risk insights adequately.

19.1.4.3.2 Significant Accident Sequences and Accident Classes/Release Categories Contributing to Offsite Consequences

Each of the 10 nonzero frequency release categories is represented by one or two severe accident sequences selected and modeled to represent the group of potential severe accidents associated with that release category. The most significant releases from failed containment stem from external steam explosion, breaks outside containment, and bypass accident sequences, represented by the release categories EVE, break outside containment, and BYP, respectively.

19.1.4.3.3 Leading Contributors to Risk from the Level 3 Internal Events Probabilistic Risk Assessment

The leading risk contributors listed in this subsection contribute to the risk of the population within 16 km (10 mi.) from each of the release categories at 72 hours after the onset of core damage, as calculated in the ESBWR Level 3 PRA for internal events at full power. Similar insights are applicable to other events presented above.

The 72-hour values bound the reported 24-hour values but are not significantly greater. For example, the societal (latent fatality) risk is $2.6 \times 10^{-11}/\text{yr}$ at 72 hours, compared with $2.0 \times 10^{-11}/\text{yr}$ at 24 hours. Also:

- The whole-body dose at 805 m (0.5 mi.) over the entire dose spectrum from 0.2 Sv to greater than 100 Sv (20 rem to greater than 10,000 rem) is well below the goal of $1 \times 10^{-6}/\text{yr}$ exceedance frequency.
- Core damage sequences representing 92 percent of the total core damage frequency do not result in containment failure (i.e., they are in the TSL release category). TSL releases associated with these noncontainment failure sequences are estimated to result in about 8 percent of the societal risk within 16 km (10 mi.). There is no individual risk contribution from the TSL releases.
- The most significant releases from failed containment stem from external steam explosion, breaks outside containment, and bypass accident sequences. The associated risk categories are EVE, break outside containment, and BYP, respectively. These risk categories account for 77 percent, 6 percent, and 4 percent of the individual risk, and 61 percent, 5 percent, and 16 percent of the societal risk, respectively.
- Together, the release categories TSL, EVE, break outside containment, and BYP account for 99 percent of the CDF, 87 percent of the individual risk, and 83 percent of the societal risk.

Based on its review of the DCD Tier 2, Revision 9, Chapter 19, the staff concludes that the applicant has identified leading contributors to risk adequately.

19.1.4.3.4 Risk-Significant Equipment/Functions/Design Features, Phenomena/Challenges, and Human Actions

GEH did not identify any risk-significant equipment, functions, design features, phenomena, challenges, and human actions as part of the Level 3 ESBWR PRA. Based on its review of the DCD Tier 2, Revision 9, Chapter 19, the staff concludes that this is acceptable.

19.1.4.3.5 Insights from Uncertainty, Importance, and Sensitivity Analyses

GEH did not report any results for uncertainty or importance analyses for the Level 3 PRA.

Throughout the various revisions of Section 10 of the PRA, the applicant presented sensitivity analyses of the offsite consequences, considering variations in meteorological conditions, release elevation, release energy (heat and buoyancy), and mission time.

The analysis considered two meteorological conditions. The first, used for the ESBWR Level 3 base case study, is comparable to the ALWR URD meteorological reference data. The second represents a narrower distribution condition. The narrower distribution was considered to represent conservative radiological consequences in certain wind sectors and with certain stability classes.

The analysis studies elevated release with and without buoyant plume energy rise, along with sensitivity on population density. It uses mission times of 24 hours and 72 hours. The results indicate that variation of certain MACCS2 input parameters, such as the meteorological conditions, would result in minute changes in relation to the measures of the three risk goals. The population dose at 80.5 km (50 mi.) does not vary much for ground versus elevated release for 24-hour and 72-hour mission times. The risk insights obtained via ground release modeling at 80.5 km (50 mi.) do not change even with elevated release modeling.

The sensitivity study showed that the three NRC risk goals and the three GEH design risk goals envelop the results of the selected variations of MACCS2 input parameters and assumptions with a margin of several orders of magnitude.

19.1.4.3.6 Conclusion

The staff has reviewed the results and insights derived from the Level 3 PRA and sensitivity studies. Based on this review, the staff concludes that the applicant has performed adequate systematic evaluations of the risk associated with the design and used them to identify risk-informed safety insights in a manner consistent with the Commission's stated goals.

19.1.5 Safety Insights from the External Events Probabilistic Risk Assessment for Operations at Power

In SECY-93-087, the NRC identified the need for a site-specific probabilistic safety analysis and analysis of external events. The ESBWR PRA analyzed four external event categories, including seismic, internal fires, high winds, and internal floods. The methods used in the ESBWR PRA to evaluate external events are acceptable to the NRC because they provide the insights necessary to determine if any design or procedural vulnerabilities exist for these external events. In addition, these methods provide insights needed for design certification requirements, such as ITAAC.

19.1.5.1 Results and Insights from the Seismic Risk Assessment

19.1.5.1.1 Summary of Technical Information

19.1.5.1.1.1 Methodology and Approach

The seismic risk assessment uses the PRA-based SMA method to calculate seismic capacities (i.e., high confidence low probability of failure [HCLPF]) for important accident sequences and accident classes. The PRA-based seismic margins approach used in this analysis evaluates the capability of the plant to withstand an earthquake of 1.67 times the SSE ($1.67 \times \text{SSE}$). The analysis involves the following two major steps: (1) seismic fragilities and (2) accident sequence HCLPF analysis. The seismic fragilities of the ESBWR SSCs are based on generic industry information and ESBWR-specific seismic capacity calculations for certain structures. The MIN-MAX method is used to determine the functional and accident sequence fragilities. In accordance with the MIN-MAX method, the overall fragility of a group of inputs combined using OR logic (i.e., seismic event tree nodal fault tree) is determined by the lowest (minimum) HCLPF input. Conversely, in accordance with the MIN-MAX method, the overall fragility of a group of inputs combined using AND logic (i.e., seismic event tree sequence) is determined by the highest (maximum) HCLPF input.

The ESBWR is designed to withstand a 0.5g (acceleration due to gravity) SSE. However, it is expected that a plant built to withstand the SSE will actually be able to withstand an earthquake of a larger magnitude. This is because the analyses used for designing the capability of SSCs to withstand the SSE have significant margin. A PRA-based margins analysis systematically evaluates the ability of the designed plant to withstand earthquakes without resulting in core damage. It does not include an estimate of the CDF from seismic events. The margins analysis is a method for estimating the “margin” above the SSE (i.e., how much larger than the SSE an earthquake must be before the safety of the plant becomes compromised).

The capability of a particular SSC to withstand beyond-design-basis earthquakes is measured in terms of the value of the peak ground acceleration (PGA) (i.e., g-level) at which there is a high confidence that the particular SSC will have a low probability of failure (i.e., HCLPF). The HCLPF capacity of a certain SSC corresponds to the earthquake level at which, with high confidence (95 percent), it is unlikely (probability less than 5×10^{-2}) that failure of the SSC will occur. An HCLPF value for the entire plant is determined by finding the lowest sequence HCLPF that leads to core damage. It is a measure of the capability of the plant to withstand beyond-design-basis earthquakes without sustaining core damage. The plant HCLPF value, which is assessed from the SSC HCLPF values, has units of acceleration. The risk-based SMA takes no credit for the nonsafety-related defense-in-depth systems. Because such systems are not seismic Category I, the analysis conservatively assumes that they become unavailable as a consequence of the seismic initiating event. Because the nonsafety-related diesel generators are assumed to be unavailable, and the failure with the lowest HCLPF value that would initiate an accident is the loss of offsite power, the SMA treats all accident sequences as SBO sequences. The analysis investigated and accounted for potential adverse interactions between assumed seismically damaged nonsafety-related SSCs and safety-related systems. The event and fault trees developed for the internal events PRA were modified to accommodate seismic events. In this way, the seismic analysis captures the random failures and human errors modeled in the internal events portion of the PRA.

19.1.5.1.1.2 Significant Accident Sequences and Leading Contributors

In the systems analysis portion of the SMA, the applicant described a set of potential accident sequences following a seismically-induced rupture of the largest pipe in the reactor coolant system (RCS). The applicant assumed that all ac power is lost at the time of the seismic event and that the ac power is unrecoverable. Consequently, these sequences reflect the impact of success and failure of passive safety systems and safety systems that rely only on direct current (dc) control power. The likelihood of components failing randomly was assumed to be insignificant compared to that for seismic-induced failures, and, therefore, the sequences did not include random events.

19.1.5.1.1.3 Insights from the Uncertainty, Importance, and Sensitivity Analyses

Neither uncertainty analyses, importance analyses, nor sensitivity analyses are available because the applicant performed an SMA rather than a seismic PRA. The explanation of seismic risk using SMA is an approach acceptable to the staff.

19.1.5.1.2 Regulatory Criteria

The NRC has indicated in SECY-93-087 and the associated SRM that a plant designed to withstand a 0.5g SSE should have a plant HCLPF capacity of at least 1.67 times the acceleration of the SSE (i.e., 0.84g).

The staff has considered the results and insights from the SMA with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report. The following objective is especially relevant to the evaluation of results and insights from the SMA: Identify risk-informed safety insights based on systematic evaluations of the risk associated with the design such that the applicant can identify and describe: (1) the design's robustness, levels of defense-in-depth, and tolerance of severe accidents initiated by either internal or external events, and (2) the risk-significance of specific human errors associated with the design.

No specific regulatory requirements govern the safety insights used to support design certification.

However, the staff used the applicable guidance from SECY-93-087 and SRP Section 19.0, Revision 2 in its review.

19.1.5.1.3 Staff Evaluation

19.1.5.1.3.1 Methodology and Approach

The methodology used to perform the SMA follows a PRA-based approach as described in SECY-93-087 and associated SRM and is therefore acceptable.

The PRA-based SMA shows that the ESBWR design can meet the expected 0.84g HCLPF value if the seismic capacities of structures, systems and components (SSCs) associated with the seismic initiated accident sequences are qualified to be above the specified acceptable design value of 0.84g. In the DCD Tier 2, Revision 9, Section 19.2.6, the applicant stated the following:

The COL Applicant will identify a milestone for completing a comparison of the as-built SSC HCLPFs to those assumed in the ESBWR SMA shown in Table 19.2-4. Deviations from the HCLPF values or other assumptions in the seismic margins evaluation shall be analyzed to determine if any new vulnerabilities have been introduced. A minimum HCLPF value of $1.67 \times \text{SSE}$ will be met for the SSCs identified in DCD, Table 19.2-4.

This COL information item (COL Information Item 19.2.6-1-A, "Seismic High Confidence Low Probability of Failure Margins") is acceptable.

19.1.5.1.3.2 Significant Accident Sequences and Leading Contributors

The staff used the results of the applicant's risk-informed SMA to identify dominant accident sequences for seismic events.

The applicant's SMA shows that sequences involving structural failure of buildings or important structures (e.g., control building (CB), RPV support) have larger seismic capacities than those involving failure of mitigating systems and therefore are considered less important. Of the 12 sequences involving failure of mitigating systems that lead to core damage, all have a seismic capacity of 0.84g. This is the result of using an assumed value (i.e., 0.84g) for component fragilities and applying the MIN-MAX method for establishing sequence-level seismic capacity. Sequence 15 of the ESBWR SMA is considered to be the most significant of these 12 sequences. This sequence leads directly to core damage following the initiating event and to seismically-induced failure of dc power because many of the other mitigating systems depend on dc power to perform their functions such that there are no success paths that are independent of dc power. Results from seismic PRAs performed as part of the Individual Plant Examination External Event program showed that seismic failures of dc batteries and electrical distribution equipment (e.g., cable trays) were among the most frequently observed dominant contributors to core damage. The staff also considers Sequences 8 and 14 of the ESBWR SMA to be potentially dominant because they lead directly to core damage following seismic failure of the ADS. Depressurization is a critical safety function for mitigation of seismic events because the passive ECCS operates at low pressure.

19.1.5.1.4 Conclusion

The applicant performed its PRA-based SMA using an approach acceptable to the staff; therefore, the analysis is acceptable. Through the PRA-based SMA, the applicant has identified significant accident sequences and potentially dominant contributors to core damage in accordance with the Commission's objectives for design certification. With COL Information Item 19.2.6-1-A, the plant HCLPF capacity of $1.67 \times \text{SSE}$ is assured for the design certification, and therefore the seismic risk is adequately addressed for the design certification as required by 10 CFR 52.47(a)(27).

19.1.5.2 Results and Insights from the Internal Fires Risk Analysis

19.1.5.2.1 Summary of Technical Information

A fire probabilistic risk assessment (FPRA) is performed taking into account that the specifics of cable routings, ignition sources, and target locations in each zone of the plant are not known at this stage of the plant design. Because of this limitation, the applicant used a simplified approach that is conservative and bounding with respect to CDF and LRF. For example, the

FPRA assumes the worst effects of fire on all equipment and systems located in each group of fire areas. That is, any fire in any fire area will cause the worst damage, and a fire ignition in any fire area continues to grow unchecked into a fully developed fire without credit for fire suppression.

The fire risk analysis uses the same PRA models as the internal events evaluation. The specific fire location determines which of the internal events sequences are applicable. These are modified to consider the effects of specific fires and include the possibility of fire propagation through potentially failed fire barriers. The analysis used bounding fire initiating event frequencies, consistent with the nature of the fire analysis.

The applicant performed the ESBWR internal FPRA according to the guidance in NUREG/CR-6850 (EPRI 1011989), "Fire PRA Methodology for Nuclear Power Facilities," issued September 2005.

The following analysis tasks, which are described in NUREG/CR-6850, apply to ESBWR FPRA model development:

- Task 1: Plant Boundary and Partitioning
- Task 2: FPRA Component Selection
- Task 3: FPRA Cable Selection
- Task 4: Qualitative Screening
- Task 5: Fire-Induced Risk Model
- Task 6: Fire Ignition Frequencies

The applicant performed subsequent analysis tasks using an approach simpler than that suggested in NUREG/CR-6850. This approach is acceptable because the impact of the detailed analysis will not affect the results from this simplified analysis due to the conservative assumptions used in the ESBWR PRA. Seismic-fire interaction (Task 13) is qualitatively evaluated.

19.1.5.2.1.1 Fire Probabilistic Risk Assessment Assumptions

The fire risk analysis is performed using conservative and bounding assumptions because the detailed cable routings and ignition sources have not been specified. The key general assumptions include the following:

- Fire ignition in any fire area may grow into a fully developed fire.
- The analysis does not take credit for any fire suppression systems. Therefore, the analysis assumes that all fires disable all potentially affected equipment in the area.
- The analysis does not take credit for the distance between fire sources and targets.
- The analysis assumes that all fire-induced equipment damage occurs at the beginning of the event.
- Design requirements have been implemented to prevent spurious actuations induced by a single fire in the RB. However, the PRA assumes that fire propagation in the RB will lead to inadvertent opening of relief valves (IORV).

Because the insights from the FPRA analysis impact the detailed design, the FPRA analysis includes more specific assumptions about each task as a result of that process. Section 12.2 of the PRA report, Revision 6, describes the detailed assumptions.

19.1.5.2.1.2 Task 1: Plant Boundary and Partitioning

The “Electrical Equipment Separation” design specification for the ESBWR provides the basic criteria for separation, both physical and electrical, of redundant safety equipment. ESBWR separation specifications are based on RG 1.75, Revision 3, “Physical Independence of Electrical Systems,” issued February 2005, and Institute of Electrical and Electronic Engineers (IEEE) Standard 384–1992, “Standard Criteria for Independence of Class 1E Equipment and Circuits.” In addition, the ESBWR design complies with the more stringent NRC policy statement of SECY-89-013, “Design Requirements Related to the Evolutionary Advanced Light Water Reactors,” dated January 19, 1989, which requires the capability for safe shutdown assuming that all equipment in any one fire area has been rendered inoperable by fire and that reentry to the fire area for repairs and for operator actions is not possible.

The plant is divided into separate fire areas. The redundant cables and equipment are separated by fire barriers to limit any damage caused by a fire and to provide a means to ensure that there is sufficient capacity to perform safety functions in case of fire. Fires within the containment are not credible during plant operation because the containment is inerted.

The ESBWR design has 3-hour fire-rated barriers to ensure the following:

- Separation of safety-related systems from potential fires in nonsafety-related areas that could affect the ability of the safety-related systems to perform their safety functions
- Separation of redundant divisions or trains of safety-related systems so that both are not subject to damage from a single credible fire that could consume everything within the given fire area
- Separation of components within a single safety-related electrical division that could present a fire hazard to another safety-related division
- Separation of redundant remote shutdown panels

The application of these separation criteria ensures adequate independence of each safety system division, such that a fire in a single fire area can affect only one safety system division. The ESBWR FPRA uses these criteria to support definitions of the major fire areas. ESBWR nonsafety-related systems with the potential to adversely affect safety-related systems are designed with similar separation requirements.

The ESBWR FPRA considers only the mitigation of fires without crediting suppression capabilities. The plant is divided into separate fire areas. Fire barriers separate the redundant cables and equipment to limit any damage caused by a fire to ensure that there is sufficient capacity to perform safety functions following a fire event.

The global plant analysis boundary uses all fire areas defined in DCD Tier 2, Revision 9, Chapter 9, which covers all of the protected area. The plant boundary includes all fire areas defined in the fire hazard analysis (FHA). The FHA fire areas include the RB, fuel building (FB), CB, turbine building (TB), electrical building (EB), radwaste building, and yard area.

19.1.5.2.1.3 Task 2: Fire Probabilistic Risk Assessment Component Selection Assumptions

The equipment and component selections are based on the following criteria:

- Equipment whose fire-induced failures will contribute to or otherwise cause an initiating event in the FPRA (including spurious actuations)
- Equipment that supports the success of mitigating system functions
- Equipment that supports the success of operator actions to achieve and maintain safe shutdown (including spurious actuations)

19.1.5.2.1.4 Task 3: Fire Probabilistic Risk Assessment Cable Selection

The cable routing assumes divisional separation and is based on current plant general arrangement drawings. The I&C cabling is based on the preliminary design of panels and remote multiplexing units (RMUs). Because of the limited design detail available at the design certification stage, detailed circuits are not available for evaluation. However, the ESBWR digital I&C system design is required to prevent spurious actuations.

19.1.5.2.1.5 Task 4: Qualitative Screening Criteria

The analysis used the following criteria to screen fire areas from consideration:

- The area does not contain equipment modeled in the PRA (or its associated circuits) identified in FPRA Tasks 2 and 3.
- Fires in the area will not lead to (1) an automatic trip; (2) a manual trip, as specified in fire procedures or plans, emergency operating procedures, or other plant policies, procedures, and practices; or (3) a mandated controlled shutdown as prescribed by plant TS because of invoking a limiting condition of operation.

19.1.5.2.1.6 Task 5: Fire-Induced Risk Model

The at-power FPRA models are based on the Level 1 and Level 2 internal events PRA models. For each fire scenario, the corresponding initiating event in the internal events PRA model is assigned with the evaluation of all failed components in the affected fire area.

The calculation of the fire-induced CDF and LRF for each fire scenario requires the determination of initiating events resulting from the fire damage and the affected mitigating systems credited in the PRA. Mitigating systems in the PRA include both safety and nonsafety equipment.

19.1.5.2.1.7 Task 6: Fire Ignition Frequencies

The NUREG/CR-6850 methodology is used to calculate the full-power fire ignition frequencies. The specific steps outlined in NUREG/CR-6850 are followed.

19.1.5.2.2 Regulatory Criteria

The staff has considered the results and insights from the internal FPRA with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report.

No specific regulatory requirements govern the safety insights used to support design certification. However, the staff used applicable guidance from SRP Section 19.0, Revision 2 in its review.

19.1.5.2.3 Staff Evaluation

19.1.5.2.3.1 *Evaluation of Methodology and Approach*

The ESBWR internal FPRA is performed according to the guidance in NUREG/CR-6850. The FPRA method documented in this report reflects a state-of-the-art fire risk analysis approach. Methodological issues raised in past fire risk analyses, including individual plant examination of external events fire analyses, have been addressed to the extent allowed by the current state-of-the-art. Therefore, the staff finds the use of this approach to perform internal FPRA acceptable.

GEH described the ESBWR plant layout drawing, fire component mapping, and cable routing information in NEDO/NEDE-33386, Revision 1, "ESBWR Plant Flood Zone Definition Drawings and Other PRA Support Information," issued May 2009. DCD Tier 2, Revision 9, Appendix 9A (Figures 9A.2-1 through 9A.2-33), includes the plant layout drawings for fire areas and fire boundaries. Tables 9A.5-1 through 9A.5-7 in DCD Tier 2, Revision 9, Appendix 9A, list additional information for these fire areas. NEDE/NEDO-33386, Section 4, includes the list of equipment located in each fire area and the cable routing information.

The mapping from fire areas to rooms, then to components and basic events, is based on the current detailed design drawings, which are subject to change. However, the separation criteria are implemented, and this is not expected to change in future modifications to the detailed designs. The cable routing assumed for the PRA fire model is based on the guidelines for separation criteria. Although the final cable routing could be different from that assumed in the PRA model, reasonable cable variations will not significantly impact the PRA results. The staff finds this approach to be acceptable.

In a number of RAIs, the staff requested specific information about the locations of the RWCU pumps and trains, a list of screened-out fire areas, and an explanation as to why the analysis did not address fires in the yard area and remote shutdown panels. The applicant addressed these questions in its responses as discussed below.

The components of RWCU trains are located in separate fire areas, as shown in DCD Tier 2, Revision 9, Appendix 9A, Figures 9A.2-1 and 9A.2-10. Table 12.6-2 of the PRA report, Appendix 12A, contains a list of screened-out areas. The remote shutdown panels will be located in separate fire areas in the RB. Since the FPRA does not take credit for the remote shutdown panels for reasons of conservatism, their location is not critical to the current PRA model. A fire in the switchyard could result in a plant trip if it results in an LOPP. The FPRA model includes such a scenario with a conservative assumption that any fire in the switchyard would result in a reactor trip. The staff finds these responses acceptable.

The staff asked GEH to search for potential smoke propagation paths, identify design and operation features to minimize smoke propagation, and assess the associated risk of smoke propagation.

GEH described the potential smoke propagation in various buildings based on the simplified plant diagram for the ESBWR. Design and operational features used to mitigate the potential risk associated with smoke propagation include following the National Fire Protection Association (NFPA) smoke control guidelines and removing smoke with HVAC systems. GEH indicated that a balanced HVAC system and the safety-related digital control and instrumentation system (Q-DCIS) address both heat dissipation and smoke removal issues.

GEH is preparing a balanced detailed HVAC system design (i.e., implementing separation criteria of RB HVAC subsystems, coating some of the Q-DCIS circuit boards, or using other equivalent methods to protect them from the postulated smoke damage). According to Appendix T, "Smoke Damage," to NUREG/CR-6850, circuit bridging is the only mode of component failure found to be of potential risk significance. Coating some of the Q-DCIS circuit boards or protecting them by other equivalent methods could significantly reduce potential smoke damage. On the other hand, a detailed HVAC design could implement separation criteria for different fire areas with safety-related equipment, which would result in negligible risks associated with smoke damage even without crediting coating of the Q-DCIS circuit boards. In summary, the risk associated with postulated smoke propagation is considered to be negligible because balanced HVAC and Q-DCIS system designs address smoke removal issues.

The ESBWR FPRA has evaluated potential fire-induced spurious valve actuations causing LOCA or incorrect valve lineup. According to the FPRA, a single fire in any fire area will not cause spurious actuation of DPVs, SRVs, or GDCS squib valves and result in a LOCA. The ESBWR I&C system is digital. A spurious signal cannot be induced by the fire damage in a fiber-optic cable. With the minimal use of the hard wires, the consequences of a postulated fire are reduced. Furthermore, two or three load drivers must be actuated simultaneously to activate the component. To eliminate spurious actuations, these multiple load drivers are located in different fire areas. Therefore, a fire in a single fire area cannot cause spurious actuation.

The ESBWR FPRA has addressed potential fire-induced spurious valve actuations causing ISLOCA. However, the FPRA considered two interfacing LOCA systems. The two systems with penetration lines are the main steamline drains upstream of the MSIVs and the feedwater system. Multiple containment isolation valves and drains are configured in different fire areas for the main steamline drain. It is unlikely that a fire could propagate across multiple fire areas and cause spurious actuations on both the containment isolation valves and the downstream valve. For the high/low-pressure interfaces on the feedwater system line A, multiple check valves are included, which prevent the opening of the path even if a spurious actuation should occur after a fire. Moreover, the detailed design has added the monitoring and alarm functions on the line between the check valve and the normally closed isolation valves to check for potential leakage which would indicate valve failure upstream. Therefore, the spurious actuation resulting from a postulated fire has a negligible impact on the ISLOCA evaluations.

New fire propagation scenarios for full-power operation were modeled by the applicant based on the plant general arrangement drawings. The FPRA model includes the possibility of fire propagation through potentially failed fire barriers. The failure probabilities of fire barriers are taken from Table 11-3 of NUREG/CR-6850, Volume 2. To perform online maintenance, some

of the fire doors may be open for access and this is not modeled in the baseline ESBWR fire PRA model. The risk increase associated with the open doors will be controlled by the plant's risk management program of 10 CFR 50.65(a)(4) when the plant is in operation, therefore the staff finds this approach acceptable.

Since the main control room (MCR) communicates with the distributed control instrumentation system (DCIS) rooms via fiber optic cables, no spurious actuation will originate from an MCR fire. The remote shutdown panels give the operators redundant locations to perform functions related to safe shutdown. However, these actions are for defense-in-depth. The ESBWR FPRA model for a postulated fire in the MCR does not credit the performance of the compensatory manual actions for safe shutdown. Instead, all operator actions are assumed failed for an MCR fire. This is a conservative approach, which the staff finds acceptable.

The ESBWR FPRA is a bounding analysis that incorporates several conservative assumptions. The fire analysis does not account for the amount of combustible material present or for the distance between fire sources and targets. The analysis assumes that a fire ignition in any fire area grows into a fully developed fire. Therefore, fires are conservatively assumed to propagate unsuppressed in each fire area and to damage all functions in the fire area. Bounding fire initiating event frequencies are used, consistent with the nature of the fire analysis. The staff finds this acceptable.

The ESBWR internal FPRA is performed according to the guidance in NUREG/CR-6850. The FPRA method documented in this report reflects state-of-the-art fire risk analysis approaches and is therefore acceptable. The FPRA model is to be maintained and updated to reasonably reflect the as-built and as-operated plant according to the PRA maintenance program described in Section 19.4 of DCD Tier 2, Revision 9. The staff documents its review of the applicant's PRA maintenance and update program in Section 19.1.2.3.4 of this report.

The ESBWR PRA does not describe the yard and service water structure/building fire layout areas since these areas are site specific. The FPRA uses conservative assumptions to analyze the fire consequences. The COL applicant will supply the fire layout areas for the yard and service water structure/building. Furthermore, the COL applicant will ensure that results of the plant-specific fire analysis are bounded by the PRA described in DCD Tier 2, Revision 9; otherwise, the COL applicant will perform a modified PRA fire analysis. This is acceptable to the staff.

19.1.5.2.3.2 Evaluation of Significant Accident Sequences and Leading Contributors

The total CDF for fire events at full power is 1.25×10^{-8} /yr. The total LRF for fire events at full power is 1.56×10^{-9} /yr.

The staff requested that the applicant provide a characterization of the dominant accident sequences and associated major contributors to CDF for each sequence. Combined, the following 10 fire scenarios, which are the leading contributors to core damage, contribute to about 80 percent of the total fire CDF:

- (1) A postulated fire in F9160 (cable tunnel B) fails all the cabling for train B components of nonsafety-related systems, including all the power cables.
- (2) A postulated fire in F9150 (cable tunnel A) fails all the cabling for train A components of nonsafety-related systems, including all the power cables.

- (3) A postulated fire in FSWYD (switchyard) results in an LOPP, and no recovery of offsite power is assumed.
- (4) A postulated fire in F3301 (non-1E electrical room) fails RWCU train A, FAPCS train A, CRD pump A, condensate and feedwater system, reactor closed cooling water system (RCCWS) train A, and FPS pump U43-P1B. The fire propagates to the DPS room.
- (5) A postulated fire in F1311 (Division I electrical room) fails Division I safety-related RMUs and load drivers, Division I uninterruptable power supply (UPS) buses, and SLCS train A. It also fails Division I safety-related control signals.
- (6) A postulated fire in F1321 (Division II electrical room) fails Division II safety-related RMUs and load drivers, Division II UPS buses, and SLCS train B. It also fails Division II safety-related control signals and some DPS control signals.
- (7) A postulated fire in F5350 (electrical equipment A) fails the train A 6.9-kilovolt switchgear.
- (8) A postulated fire in F3302 (non-1E electrical room) fails RWCU train B, FAPCS train B, CRD pump B, condensate and feedwater system, RCCWS train B, and FPS pump U43-P1B. The fire propagates to cable tunnel B.
- (9) A postulated fire in F4197 (turbine equipment) fails condensate and feedwater system, turbine closed cooling water system (TCCWS), and the instrument air and service air systems.
- (10) A postulated fire in F3302 (non-1E electrical room) fails RWCU train B, FAPCS train B, CRD pump B, condensate and feedwater system, RCCWS train B, and FPS pump U43-P1B.

The most important fire sequences involve fires in the cable tunnels that disable either plant investment protection (PIP)-A or PIP-B control signals and power supplies. Postulated fire propagation between the nonsafety distributed control and instrumentation system (N-DCIS) A room and the DPS room also has a relatively higher contribution because it disables both the PIP-A and DPS controls. Other noteworthy fire-induced initiating events include the fires in the switchyard that result in LOPP and in the RB that disable Division I or II electrical equipment.

The quantification of the LRF is similar to the CDF calculations, with the addition of the Level 2 fault tree models and phenomenological point estimates. The fire-induced risk model used for Level 1 quantification is not changed since the component selection and cable selection tasks have already considered all components, including the Level 2 components.

The leading contributors to the LRF are similar to those for the CDF except that the event of fire propagation between the N-DCIS A room and the DPS room contributes to approximately 44 percent of the total LRF.

Based on the preceding discussion, the staff concludes that the applicant has adequately discussed the dominant accident sequences.

19.1.5.2.3.3 *Evaluation of Risk-Significant Functions/Features, Phenomena/Challenges, and Human Actions*

The ESBWR design features safety system redundancy and physical separation by fire barriers. The design ensures that, in all cases, a single fire limits damage to a single safety system division or defense-in-depth system. Fire propagation to neighboring areas presents a relatively minor risk contribution except for fire propagation between the N-DCIS train A room and the DPS room in the CB. The reason for this exception is that the fire in the N-DCIS room is postulated to fail RWCU train A, FAPCS train A, CRD pump A, condensate and feedwater system, RCCWS train A, and FPS pump U43-P1B. Together with the equipment in the DPS room, these systems are important to preventing core damage.

The ESBWR internal events PRA model assumes that both trains of the SLCS are required to mitigate the accident consequences from the ATWS sequences. Consequently, a fire that affects a single train of the SLCS leads to significant contributions from the ATWS sequences to the total fire CDF.

Fire in the control room traditionally requires the operator to take actions to control the plant manually. One relevant feature of the ESBWR design is that a fire in the control room does not affect the automatic actuations of the safety systems. Additionally, the existence of remote shutdown panels allows the opportunity to perform manual actuations for failed automatic actuations that may occur.

Similar to the internal events analysis, the FV importance values for fires are low, which indicates a balanced risk profile.

Based on the preceding discussion, the staff concludes that the applicant has successfully identified risk significant functions and features.

19.1.5.2.3.4 *Evaluation of Insights from the Uncertainty, Importance, and Sensitivity Analyses*

The applicant performed a sensitivity analysis for the Level 1 fire model using focused PRA studies. The analysis evaluated the impact of failing all nonsafety systems, along with the impact of failing all nonsafety systems except those designated as RTNSS. The former study generated a CDF of $5.13 \times 10^{-5}/\text{yr}$, and the latter study generated a CDF of $2.95 \times 10^{-7}/\text{yr}$.

The results for the focused fire sensitivity study showed significant impact on the CDF with the failure of nonsafety systems, both within the scope of RTNSS and outside the scope of RTNSS. The inclusion of the RTNSS SSCs in the model reduces the CDF by approximately two orders of magnitude compared to crediting safety-related systems only. The results of the Level 1 focused fire sensitivity study show that the NRC goal of $1 \times 10^{-4}/\text{yr}$ CDF is met for the baseline Level 1 fire analysis, the focused study, and the RTNSS sensitivity analyses. The fire analysis is very conservative with no credit taken for fire suppression or fire severity factors.

The Level 2 focused fire sensitivity study, in which all nonsafety systems are failed, generated an nTSL (nontechnical-specification leakage, which is equivalent to LRF) release frequency of $4.18 \times 10^{-5}/\text{yr}$. The RTNSS study generated an nTSL release frequency of $8.34 \times 10^{-8}/\text{yr}$. The results for these studies show significant impact to the nTSL release frequency with the failure of nonsafety systems both inside and outside the scope of RTNSS. The results show a decrease of three orders of magnitude in the nTSL frequency with the RTNSS SSCs available

compared to safety-related systems only. The nTSL results of the Level 2 focused fire sensitivity study show that the NRC goal of $1 \times 10^{-6}/\text{yr}$ for LRF is met when RTNSS SSCs are included, but not met for the focused Level 2 fire study with all nonsafety systems failed.

Tables in Section 11 of the PRA report, Revision 6, present the results of the FPRA sensitivity studies in the column entitled, "Difference." These tables include 11.3-4, 11.3-6, 11.3-8, 11.3-11, 11.3-19, 11.3-20, 11.3-22 through 11.3-25, 11.3-28, 11.3-30, 11.3-32, 11.3-34, and 11.3-36 through 11.3-39. Section 11 does not define "Difference." Because it could not reproduce some of the results, the staff was concerned that there may be some errors in the calculation of "Difference." The staff tracked RAI 19.1-160 as an open item in the SER with open items.

In Revision 4 of the PRA report, the applicant provided the definition of "Difference." The applicant also revised all of the tables mentioned in RAI 19.1-160 to show the correct values based on the definition of "Difference." The staff evaluated the results and verified its accuracy. Therefore, RAI 19.1-160 and the associated open item are resolved.

In addition to the focused PRA studies, the applicant conducted a series of sensitivity studies to determine the impact to CDF and LRF in the full-power and shutdown FPRA models from the uncertainties in the model assumptions. The full-power fire model sensitivity studies are grouped as follows:

- Plant partitioning
- Fire risk in transition modes
- Fire ignition frequencies
- Separation criteria
- Fire barrier failure probabilities

The results of the plant partitioning sensitivity study indicated that DPS is critical in mitigating the fire risks, which warrants the separation of the DPS cabinets from other cabinets in Room 3301. The risk increase associated with the merging of Rooms 3301 and 3140 into a single fire area is moderate. In both cases, the resulting total fire risks are still more than two orders of magnitude lower than the NRC goals for CDF and LRF (i.e., $1 \times 10^{-4}/\text{yr}$ for CDF and $1 \times 10^{-6}/\text{yr}$ for LRF).

The sensitivity study of fire in transition modes indicated that fire area F1170 (drywell and containment fire area) warranted further study. This room is inert during operation (Mode 1) and deinerted in shutdown (Modes 2, 3, or 4). The results of the sensitivity studies indicate that total baseline CDF and LRF in these modes are at least three orders of magnitude below the goals.

The results of the fire ignition frequencies sensitivity study confirmed that the fire ignition frequencies used in the baseline FPRA model are conservative. The staff finds this acceptable.

The results of the separation criteria sensitivity analysis showed the importance of the RTNSS requirements for RCCWS and plant service water system (PSWS) to ensure separation criteria.

The results of the fire barrier failure sensitivity/importance study indicated that the risk increases with several fire barrier failures are significant. The three most risk-significant increases for barrier failures are the barrier between cable tunnels A and B, the barrier between the N-DCIS electrical room A and the DPS room, and the barrier between the N-DCIS electrical room B and cable tunnel B.

The results of importance measures for the at-power fire CDF confirmed the importance of components in cutsets of the top fire sequences.

By crediting the DPS and ARI functions, along with the safety-related systems, the ESBWR LRF can be significantly reduced to satisfy the safety goal of 1×10^{-6} /yr for LRF in the Level 2 fire model.

19.1.5.2.4 Conclusion

The staff has reviewed the results and insights derived from the fire PRA and sensitivity studies. Based on this review, the staff concludes that the applicant has performed adequate systematic evaluations of the risk associated with the design and used them to identify risk-informed safety insights in a manner consistent with the Commission's stated goals.

19.1.5.3 *Results and Insights from Internal Flooding Analysis*

19.1.5.3.1 Summary of Technical Information

The objective of the ESBWR internal probabilistic flood analysis is to identify and provide a quantitative assessment of the CDF and releases that result from internal flooding events. The floods may be caused by large leaks resulting from the rupture or cracking of pipes, piping components, or water containers, such as storage tanks. Another possible flooding cause is the operation of fire protection equipment.

A flooding event may result in an initiating event and may also disable mitigating systems. Thus, buildings containing mitigating equipment credited in the PRA accident sequence analysis, or equipment whose loss could cause an initiating event, are of interest in the flooding analysis.

The ESBWR analysis considers flood scenarios in the following buildings:

- RB
- CB
- FB
- TB
- EB
- Service water building
- Circulating water pump-house
- Fire protection enclosure
- Tunnels and galleries connected with the buildings listed above

The study does not consider floods occurring in the remaining ESBWR buildings because those flood waters cannot propagate to any of the above buildings.

Buildings are divided into flooding zones and are further subdivided into systems that have the potential to cause flooding within the flooding zone. The analysis does not consider flood zones that do not contain flood sources and do not have floods propagating to the zone. Flood zones that do not cause a reactor trip at power or do not contain mitigating equipment modeled in the PRA are also screened from further analysis. Finally, if the flood zone contains mitigating equipment, such as sump pumps, that would prevent unacceptable flood levels, then the flood

zone is not analyzed further. However, the failure probability of these components is considered in the PRA model.

Section 13.2 of the PRA report lists the assumptions used in the flooding analysis. The major assumptions include the following:

- Nonqualified submerging equipment (motors or solenoids for valves, control cabinets, and circuitry) is assumed to result in equipment failure.
- MOVs require the application of current to the motor to change the valve position. Without power, the valve will remain in its current position. Flooding or spraying or both of an MOV will therefore cause the valve to fail as is.
- Passive components, such as check valves, pipes, and tanks, are not considered to be vulnerable to flooding effects.
- Flooding has no effect on CCFs.
- Water in a stairwell or propagating into a stairwell preferentially continues to travel down the stairwell as opposed to propagating under a door leading outside the stairwell.
- The mission time of the active equipment credited in the flooding risk analysis is 24 hours. This is the same time used in the internal events PRA.
- The flooding analysis does not consider concurrent flooding events from different sources.
- Components that are environmentally qualified inside containment are considered to be invulnerable to the effects of flooding because they are qualified for a post-LOCA environment inside containment. Environmentally qualified equipment outside containment may not be qualified to a severe environment.
- The internal flooding analysis uses the same system success criteria as used in the internal events PRA.
- Electrical connections in the termination boxes on the containment wall are adequately protected to prevent flood-induced failure.
- Fire doors are not watertight.
- Walls are assumed to be capable of withstanding the expected maximum flood loading. Therefore, walls are assumed to remain intact throughout a flooding event.
- Electrical circuit fault protection is assumed to have been designed to defend plant electric circuits via protective relaying, circuit breakers, and fuses. Therefore, loss of a component because of flooding will not result in the loss of the bus that supplies power to the affected component.
- For floor drains, appropriate precautions, such as check valves, backflow prevention, and siphon breaks, are assumed to prevent backflow and any potential flooding.

- The doors connecting the control and RBs with the EB galleries are assumed to be watertight; flooding of the galleries up to the ground-level doors is assumed to generate an alarm in the control room, and procedures direct the immediate closure of the doors upon receipt of an alarm.
- The operation of the components located in containment are assumed to be unaffected in a LOCA or if the drywell is flooded to a level equivalent to the level of the suppression pool.
- Equipment located in the yard is not considered susceptible to internal flooding damage.

The applicant performed a screening analysis based on a general review of all systems for the ESBWR. This screening removed systems that would not be considered flood sources from further consideration. After screening, the following plant systems were considered as potential flood sources at power:

- NBS
- CRDS
- SLCS
- FAPCS
- RWCU/SDC system
- Resin transfer system
- Turbine main steam system
- Condensate and feedwater system
- Heater drain and vent system
- Condensate purification system
- Moisture separator reheater system
- Extraction steam system
- Circulating water system
- Makeup water system
- Condensate storage and transfer system
- PSWS
- Diesel generator
- FPS
- Station water system
- Auxiliary boiler oil storage and transfer system

Systems inside containment considered in the flooding analysis as potential flood sources are those in which a break would cause a LOCA. Because the internal events PRA analysis already models LOCA scenarios in containment, the internal flooding analysis does not model these events. Therefore, the at-power internal flooding analysis does not analyze further any flood scenarios in containment.

The applicant calculated the initiating event frequency for each flood zone by summing the frequencies for flood components and piping for the system under consideration. At-power flooding frequencies are included if the failure of the system directly causes a reactor trip, the flooding caused by the failure fails equipment which leads to a reactor trip, or if PRA-related equipment would likely be affected.

For postulated flood events occurring at power, the applicant used the general transient initiating event category and associated accident sequence logic to model the accident

sequence progression. The calculated flood initiator frequency and associated equipment impacts are propagated through the general transient Level 1 internal events accident sequence logic for the flood scenario. The applicant also performed a Level 2 analysis for the flooding scenarios.

19.1.5.3.2 Regulatory Criteria

The staff has considered the results and insights from the internal flooding PRA with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report.

No specific regulatory requirements govern the safety insights used to support design certification.

However, the staff used applicable guidance from SRP Section 19.0, Revision 2 in its review.

19.1.5.3.3 Staff Evaluation

19.1.5.3.3.1 *Evaluation of Methodology and Approach*

GEH has performed the PRA flooding analysis. The calculated flood initiator frequency and associated equipment impacts are propagated through the general transient Level 1 internal events accident sequence logic for the flood scenario. NEDE/NEDO-33386, Revision 1, provides a list of the equipment located in each flooding area the PRA credits for accident mitigation. The equipment includes safety as well as nonsafety components.

The PRA report provides a list of screened flooding areas. The screened areas are those having not been considered as potential flood sources, or the areas containing PRA equipment which have no probabilistic impact. The staff agrees with this assessment.

NEDO/NEDE-33386 lists all unscreened flooding sources located in an unscreened area. Flooding initiating event frequency in the flooding zone is based on all potential sources, including pipes, pumps, valves, tanks, heat exchangers, and expansion joints within the flooding zone.

Components that are environmentally qualified inside containment are considered invulnerable to the effects of flooding because they are qualified for a post-LOCA environment inside containment. The staff finds this assumption acceptable.

Flooding propagates between areas. The model includes those areas where propagation is likely, unless adequate water removal is available (i.e., via sump pumps) to prevent flooding of the target area. Systems that do not have enough capacity to flood an area have been removed from consideration. The analysis considers aspects that affect flood progression in each building. Depending on the building and the origin of the flood, the analysis considers the following aspects that affect flood progression:

- Automatic flood detection systems
- Automatic systems to terminate flooding
- Watertight doors to prevent the progression of flooding
- Sump pumps
- Other design or construction characteristics that contribute to minimizing the consequences of flooding

The NEDO/NEDE-33386 flooding mapping report considers the scenario in which flooding from main steam and feedwater pipes located in the steam tunnel propagates to the RB.

The mission time of the active equipment credited in the flooding risk analysis is 24 hours. The internal events PRA uses the same timeframe; therefore, the staff finds it acceptable.

The internal flooding analysis treats breaks in support systems, such as the service water system, RCCWS, and TCCWS, explicitly instead of assigning them the same consequences as the failure of the systems themselves, as described in Revision 6 of the applicant's PRA.

The analysis applied a recovery factor of 0.01 to the circulating water flooding scenario in the TB to account for automatic closure of isolation valves and automatic trip of circulating water pumps.

The internal probabilistic flood analysis takes into account equipment locations based on existing plant layout drawings. It assumes that the pipe routed to or from the equipment would follow certain logical paths. For example, pipe is routed through pipe chases in battery rooms instead of being routed through the battery room. Another logical path is the shortest route, which reduces piping and fabrication cost.

The internal flooding PRA model is to be maintained and updated to reasonably reflect the as-built and as-operated plant according to the PRA maintenance program described in DCD Tier 2, Revision 9, Section 19.4. The staff's review of the applicant's PRA maintenance and update program appears in Section 19.1.2.3.4 of this report.

NEDE/NEDO-33386 does not describe the yard and service water structure/building flooding areas since these areas are site specific. The internal flooding PRA uses conservative assumptions to analyze flooding in these areas.

19.1.5.3.3.2 *Evaluation of Significant Accident Sequences and Leading Contributors to Risk*

The total CDF for full-power internal flooding events is $3.30 \times 10^{-9}/\text{yr}$. The total release frequency for internal flooding events excluding TSL at full power is $4.8 \times 10^{-10}/\text{yr}$.

The following 10 flooding scenarios are the leading contributors to core damage and, combined, they contribute to about 36 percent of the total flooding CDF:

- (1) Flooding in the TB main condenser area caused by a small pipe leak of RWCU/SDC and CCF of rods to insert results in core damage.
- (2) Flooding in the TB at elevation 1,400 millimeters (mm) (4.59 ft) caused by a large pipe leak in the condensate and feedwater system and CCF of rods to insert results in core damage.
- (3) Flooding in the TB at elevation 4,650 mm (15.26 ft) caused by a large pipe leak in the condensate and feedwater system and CCF of rods to insert results in core damage.
- (4) Flooding in the TB at elevation 4,650 mm (15.26 ft) caused by a large pipe leak of the "A" PSWS train and CCF of rods to insert results in core damage.

- (5) Flooding in the TB at elevation 4,650 mm (15.26 ft) caused by a large pipe leak of the “B” PSWS train and CCF of rods to insert results in core damage.
- (6) Flooding in the TB at elevation 1,400 mm (4.59 ft) caused by a large pipe leak of the “A” PSWS train and CCF of rods to insert results in core damage.
- (7) Flooding in the TB at elevation 1,400 mm (4.59 ft) caused by a large pipe leak of the “B” PSWS train and CCF of rods to insert results in core damage.
- (8) Flooding in the RB at elevation 11,500 mm (37.73 ft) caused by a large pipe leak of the “A” RWCU/SDC and CCF of rods to insert result in core damage.
- (9) Flooding in the TB at elevation 1,400 mm (4.59 ft) caused by a large pipe leak in the FPS and CCF of rods to insert results in core damage.
- (10) Flooding in the TB at elevation 4,650 mm (15.26 ft) caused by a large pipe leak in the FPS and CCF of rods to insert results in core damage.

The CET release category frequencies are summarized as follows:

RELEASE CATEGORY	FREQUENCY
TSL	$2.83 \times 10^{-9}/\text{yr}$
Containment bypass (BYP)	$2.46 \times 10^{-10}/\text{yr}$
Filtered release (FR)	$2.10 \times 10^{-10}/\text{yr}$
Overpressure because of failure of long-term CHR	$1.98 \times 10^{-11}/\text{yr}$
Overpressure because of vacuum breaker failure	$1.81 \times 10^{-12}/\text{yr}$

The combined release frequency excluding TSL is about $4.78 \times 10^{-10}/\text{yr}$.

19.1.5.3.3.3 Evaluation of Risk-Significant Functions/Features, Phenomena/Challenges, and Human Actions

Because of the inherent ESBWR flooding mitigation capability, only a few flooding-specific design features are key in the mitigation of significant flood sources. These features include the following:

- Using watertight doors in the accesses to tunnels and galleries from the control building and RB
- Not locating flood sources with a significant volume of water in the electrical equipment rooms located in the RB
- Locating an automatic circulating water system pump trip and valve closure on high-water level in the condenser pit

The most important flood sequences during at-power conditions involve leaks in the TB main condenser area, the EB general area, the TB’s first floor, and the service water pumphouse.

The cutsets associated with these sequences involve the common-cause software failures on the digital control systems and failures of the single components that disable the ac power supplies or the IC/PCCS pool makeup.

During the initial phase of the ESBWR design, the applicant identified a significant flood risk in the CB because of a break in FPS piping. Based on this PRA insight, the design specifications now require that the FPS pipes and fire hose stations be relocated outside of the CB such that a piping failure does not result in a significant flood.

The important flooding sequences do not impose additional challenges to any of the PCCSs or the BiMAC. Therefore, the insights into internal events containment performance can be directly used for internal flood sequences.

The estimated offsite consequences resulting from external events under at-power conditions are less than the defined individual, societal, and radiation dose limits.

19.1.5.3.3.4 Evaluation of Insights from the Uncertainty, Importance, and Sensitivity Analyses

The applicant performed a sensitivity analysis for Level 1 internal flooding using focused PRA studies involving (1) failing all nonsafety systems and (2) failing all nonsafety systems except those designated as RTNSS. GEH performed this sensitivity analysis using the conservative PRA flooding model developed for the PRA report, Revision 5. The flooding baseline CDF for this model is $6.95 \times 10^{-9}/\text{yr}$. The Level 1 focused flood analysis with all nonsafety systems failed generated a CDF of $9.39 \times 10^{-5}/\text{yr}$; the RTNSS study generated a CDF of $4.36 \times 10^{-7}/\text{yr}$. The results for the focused flood sensitivity analysis showed significant impact to the CDF upon failure of the nonsafety systems, both with and without RTNSS. The inclusion of RTNSS in the model reduces the CDF by approximately three orders of magnitude as compared to the CDF when crediting safety-related systems only. Based on the Level 1 focused flood sensitivity analysis results, both the focused flood model and the RTNSS sensitivity scenarios meet the NRC goal of $1 \times 10^{-4}/\text{yr}$ CDF.

The Level 2 focused flood model with all nonsafety systems failed generated an nTSL (equivalent to LRF) release frequency of $9.22 \times 10^{-5}/\text{yr}$. The RTNSS study generated an nTSL release frequency of $3.12 \times 10^{-7}/\text{yr}$. The results of the focused flood sensitivity study showed significant impact to the nTSL release frequency with the failure of nonsafety systems, both with and without RTNSS. The results showed a decrease of about three orders of magnitude in the nTSL frequency with RTNSS available as compared to the frequency when crediting safety-related systems only. Based on the Level 2 focused flood sensitivity study nTSL results, the NRC goal of $1 \times 10^{-6}/\text{yr}$ LRF is met for the RTNSS sensitivity scenarios, but not for the focused flood model that does not credit nonsafety systems. By crediting the RTNSS systems, the NRC goal for LRF in the Level 2 flooding analysis are met.

The staff issued RAI 19.1-161 asking GEH to correct a typographical error in Table 11.3-30 of the PRA report and revise the text to reflect that the goal of $1 \times 10^{-6}/\text{yr}$ has been exceeded for the Level 2 flood focused model crediting only the safety systems. The staff was tracking RAI 19.1-161 as an open item in the SER with open items. The PRA report, Revision 4, presents these corrections. Therefore, RAI 19.1-161 and the associated open item are resolved.

The results of importance measures for the at-power internal flooding CDF confirmed that components in cutsets of top flooding sequences are important from a risk perspective.

19.1.5.3.4 Conclusion

The staff has reviewed the results and insights derived from the flooding risk analysis and sensitivity studies. Based on this review, the staff concludes that the applicant has performed adequate systematic evaluations of the risk associated with the design and used them to identify risk-informed safety insights in a manner consistent with the Commission's stated goals.

19.1.5.4 *Results and Insights from High-Winds Analysis*

19.1.5.4.1 Summary of Technical Information

The staff's review of the ESBWR high-winds risk assessment is based on the results reported in Section 14 of the PRA report, Revision 6, and DCD Tier 2, Revision 9, Section 19.2.3.2.3. The applicant developed separate ESBWR high-winds risk assessments for tornado initiators and hurricane initiators. The risk assessment and the staff's evaluation encompass plant operation at power, in cold shutdown, and in refueling modes. Section 19.1.6.2.3 of this report discusses the risk from high winds at shutdown and refueling.

The applicant's high-winds risk analysis presented in the PRA report, Revision 6, is based on the robustness of the ESBWR structures. The ESBWR is designed for a tornado wind load of 147.5 meters per second (m/s) (330 miles per hour [mph]), which is assumed to be the maximum windspeed that will not challenge the safety-related structures. In addition, the ESBWR is designed for extreme windspeed (i.e., hurricanes) of 67.1 m/s (150 mph) for seismic Category I and II structures and 58.1 m/s (130 mph) for nonseismic structures. The only exceptions are the service water building, and EB structures, which are nonseismic and have a design-basis hurricane basic windspeed of 87.2 m/s (195 mph).

The PRA assumes seismic Category I and II structures will be essentially undamaged by the windspeed of all hurricanes and tornadoes. The PRA assumes that hurricane and tornado missiles will not do significant damage to seismic Category I structures or equipment that is below grade. The PRA also assumes that only the most powerful tornado missiles can significantly damage seismic Category II structures. These assumptions are important because most of the equipment needed to keep the core cool during the first 72 hours of the event is located in the RB, which is a seismic Category I structure.

Because high winds are not expected to damage the most important structures housing safety and nonsafety equipment, and because loss of offsite power (or LOPP) would be expected in a high-winds event, the applicant chose to model high winds in the PRA by developing the event tree for LOPP. The assessment uses the internal events PRA event tree for LOPP, system fault trees (modified for loss of certain components and structures caused by high winds), and success criteria for LOPP events to calculate the risk from extended loss of offsite power resulting from high winds.

As documented in Tables 14.6-1 and 17.1-1 of the PRA report, Revision 6, the CDF for high winds at power is estimated to be about 9×10^{-9} /yr, which is approximately one-half the estimated internal events CDF. The PRA estimates LRF for high winds at power to be about 1×10^{-9} /yr, which is comparable to the LRF for all internal events.

The insights about risk from tornadoes and hurricanes in the PRA are similar to those associated with internal event long-term LOPP sequences.

19.1.5.4.1.1 *Methodology and Approach for Tornadoes*

The tornado risk analysis presented in the PRA report, Revision 6, is based on the premise that (1) plant structures built to seismic Category I and II requirements are invulnerable to the direct effects of tornado winds, (2) seismic Category I structures will not experience any significant damage from tornado missiles, (3) equipment located below grade will not be damaged by tornado missiles, and (4) seismic Category II structures will only be significantly damaged by the most powerful tornado missiles. The PRA reports results for both the Fujita Scale³ (or F-scale) and the Enhanced Fujita Scale (EF-scale). The assessment assumes that, following a strike by winds from an EF2 or greater tornado, preferred power will be lost (i.e., there will be an extended loss of offsite power that cannot be recovered). The assessment assumes equipment housed in seismic Category I and II structures will operate with normal equipment failure rates. Table 14.3-2, “ESBWR Tornado Wind—PRA Predicted Structure Damage,” in the PRA report, Revision 6, provides the assumptions on the amount of damage that structures would receive from various classes of tornadoes. (Table 19.1-11 of this report summarizes this table.) The applicant assumed that EF5 tornado missiles would significantly damage seismic Category II structures but not seismic Category I. In contrast, the applicant assumed that hurricane missiles (which have a lower velocity than some tornado missiles) would not significantly damage any seismic Category I or II structures.

The applicant performed its tornado risk assessment by taking the following steps:

- Calculate the tornado hazard frequency.
- Evaluate the tornado-induced plant effects.
- Calculate the tornado-induced CDFs and release frequencies.

The risk assessment uses the data and method from NUREG/CR-4461, Revision 1, “Tornado Climatology of the Contiguous United States,” to calculate the tornado strike frequency. The risk assessment segregates the data into three bins—EF2 and EF3 tornadoes, EF4 tornadoes, and EF5 tornadoes. The number of EF0 and EF1 tornadoes observed was discarded because the applicant assumed that these tornadoes would not significantly damage structures on site and would cause only LOPP. The PRA states that the frequency of such power losses is captured under the initiating events for internal events LOPP. The applicant chose to use data from the central region of the United States, which should encompass most ESBWR sites, because the frequencies of occurrence and tornado intensities in that region are the highest in the nation. In addition, in calculating the tornado strike frequencies, the applicant used a characteristic length, w_s , equal to 121.92 m (400 ft), which is twice that assumed in NUREG/CR-4461, Revision 1, effectively doubling the frequency of the assumed tornado strikes. This results in an at-power strike frequency for the ESBWR plant design for EF2/EF3, EF4, and EF5 tornadoes of $1 \times 10^{-4}/\text{yr}$, $4 \times 10^{-6}/\text{yr}$, and $5 \times 10^{-7}/\text{yr}$, respectively.

The applicant then entered these occurrence frequencies into the at-power internal events PRA event tree for LOPP. Fault trees, developed for the at-power LOPP event tree, are modified to take into account the effects that tornadoes will have on various components and structures. The fault trees are then input into the LOPP event tree to estimate the CDF from extended loss of offsite power due to tornadoes. The high-winds risk assessment for tornadoes assumes that equipment located in the yard or in nonseismic structures, including the TB, service water

³ Damage caused by a tornado is rated by the Fujita Scale. The higher the Fujita Scale number, the faster the rotational speed and more destructive the tornado. The Enhanced Fujita Scale is an updated version of the Fujita Scale that estimates the rotational speeds of tornadoes somewhat lower than the Fujita Scale.

building, and EB, will always fail if an EF2 or stronger tornado strikes the site. RTNSS structures are assumed to fail for EF4 and stronger tornadoes, and seismic Category II structures are assumed to be damaged by tornado missiles for EF5 tornadoes.

Table 14.6-1 in the PRA report, Revision 6, displays the estimated CDF and LRF from high winds when the plant is at power and when the plant is in shutdown. The estimated CDF from an at-power EF2 to EF3 tornado strike on an ESBWR is 9×10^{-12} /yr. The estimated CDF for EF4 tornadoes at power is 8×10^{-10} /yr. The estimated CDF for EF5 tornadoes at power is 1×10^{-10} /yr. The estimated CDF from all tornadoes when an ESBWR is shut down is 5×10^{-11} /yr. The LRF from tornadoes when the plant is at power is 8×10^{-10} /yr for EF4 tornadoes and 1×10^{-10} /yr for EF5 tornadoes, with LRF for EF2/EF3 tornadoes a much smaller contributor. The LRF from EF4 and EF5 tornadoes is significantly larger because the applicant assumed that the TB, which houses the outboard MSIVs within the steam tunnel, would be destroyed if such powerful tornadoes were to strike the plant.

19.1.5.4.1.2 Methodology and Approach for Hurricanes

Similar to tornadoes, the applicant based its risk analysis for hurricanes on the premise that plant structures built to seismic Category I and II requirements and to RTNSS standards would not be significantly damaged by hurricane winds and associated missiles. The assessment assumes that the equipment housed within these structures will operate with normal equipment failure rates during and after a hurricane. Nonseismic structures, with the exception of the TB, service water building, and EB structures, are assumed to fail for Category 3 and higher hurricanes, as is equipment located in the open. All structures are assumed to be able to withstand the winds associated with Category 1 and Category 2 hurricanes. The only impact on the site from such hurricanes is LOPP, with no additional equipment failures associated with the hurricane. Offsite power is assumed to be lost and unrecoverable for all hurricanes. The analysis assumes that the frequency of losses of power for Category 1 and Category 2 hurricanes is subsumed in the risk assessment's treatment of LOPP for internal events. The risk assessment assumes that the maximum speed of hurricanes is greater than 69.3 m/s (155 mph).

The high-winds risk analysis presented in the PRA report, Revision 6, makes the following additional assumptions and statements regarding hurricanes:

- The classification of the hurricane winds used in the ESBWR high-winds analysis is based on the Saffir-Simpson scale.
- All at-power ESBWR high-winds analyses, including hurricane high winds, assume the plant is operating at full power. This approach is assumed to be conservative for the hurricane high-winds analysis because sufficient advanced warning and procedures would enable the plant to be placed into a safe condition (shutdown operations) before a high-winds event. Implicit in this assumption is that (1) the plant will go to Mode 4 and will not deinert in Mode 4 when the plant shuts down in anticipation of a hurricane strike, and (2) in anticipation of a hurricane strike, the plant will ensure that equipment credited in the high-winds PRA is available. These implicit assumptions are captured as important PRA insights.
- The FPS piping that provides makeup water to the ICS/PCC pool and water for reactor water coolant/inventory control is dedicated piping that has no fire hydrants, standpipes, or large piping external to a seismic Category I structure and has no piping that is exposed such that it could be damaged by a hurricane-induced missile.

- Straight winds are of lesser velocity than hurricanes or tornadoes and are assumed to pose minimal challenges to the plant design.
- When the reactor well is flooded (Mode 6 [Flooded]), the risk associated with LOPP is negligible because of the large amount of water stored above the core. This water is assumed to ensure core cooling over a long period (i.e., significantly greater than 24 hours).

The applicant performed a hurricane risk assessment taking the following steps:

- Calculate the hurricane-induced LOPP frequency.
- Evaluate the hurricane-induced plant effects.
- Calculate the hurricane-induced CDFs and release frequencies.

The ESBWR hurricane risk analysis presented in the PRA report, Revision 6, does not use structural fragility curves to evaluate the potential that hurricane winds might significantly damage seismic Category I, seismic Category II, or RTNSS structures. The analysis assumes that no significant damage would occur to these structures because of their robust design criteria; instead, the analysis uses data from NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," Volume 1, "Analysis of Loss of Offsite Power Events: 1986–2004," to estimate the hurricane-induced LOPP frequency. The ESBWR hurricane risk assessment took the number of losses of offsite power that occurred at nuclear power plants in Florida, Louisiana, and North Carolina as the result of hurricanes during a specific 19-year period and divided it by the number of reactor critical-years (cyr) that nuclear power plants located in these States had operated during the same period. The risk assessment uses this estimate (i.e., 7.6×10^{-2} per reactor calendar year) as the frequency of a hurricane striking a coastal plant when the plant is at power, causing a loss of offsite power and potentially causing other damage that might lead to core damage and fission product release. The staff considers this estimate to be conservative for most sites in the United States.

The applicant then entered this occurrence frequency into the at-power internal events PRA event tree for LOPP. Fault trees, developed for the at-power LOPP event tree, were modified to take into account the effects that hurricanes will have on various components and structures, and the fault trees were then input into the LOPP event tree to estimate the CDF from extended loss of offsite power resulting from tornadoes.

In the DCD, the applicant stated that the high-winds risk assessment was conservative in that it did not credit alternative, onsite water sources beyond the condensate storage tank. However, GEH did not quantify the degree of conservatism.

Section 14.7, "Insights," of the PRA report, Revision 4, stated that the estimated CDF and LRF for all analyzed scenarios, while using a bounding analysis, were similar to the internal events results. In RAI 19.1-185, the staff disagreed with the term "bounding analysis" for all sites. In response, the applicant provided an acceptable draft modification to the PRA text. The staff confirmed the modification was made in Revision 5 to the PRA and considers this RAI resolved.

In RAI 19.1-165 the applicant was asked if, in light of the variation in strike frequency among different sites in the United States, they had done a sensitivity study on hurricane strike frequency. RAI 19.1-165 was being tracked as an open item in the SER with open items. In response, the applicant stated that a sensitivity study was not performed because their analysis of strike frequency was bounding for all sites. As discussed above, the applicant subsequently characterized their analysis in the DCD as bounding for most sites. The staff finds that a

sensitivity study is not necessary because the applicant's analysis bounds the frequency for most sites, and COL applicants will need to provide a site specific analysis if their site is not bounded by the analysis in the referenced DCD. Therefore, RAI 19.1-165 and the associated open item are resolved.

Table 14.6-1 in the PRA report, Revision 6, displays the estimated CDF from high-winds initiators. The estimated CDF from an at-power hurricane is 8×10^{-9} /yr. The at-power CDF estimate for hurricanes is comparable to total CDF for internal events (i.e., approximately one-half the internal events estimated CDF).

The applicant estimated the expected LRF caused by hurricanes. GEH assumed that at-power events would start with the containment intact, which required estimating the conditional probability of containment failure given core damage from an extended loss of offsite power event with hurricane-induced damage to some structures. The LRF for hurricanes at power is 3×10^{-10} /yr. This estimate is a factor of 3 less than that estimated for tornadoes, although the CDF from hurricanes is higher than for tornadoes. The at-power hurricane LRF is smaller than the at-power tornado LRF because EF4 and EF5 tornadoes fail all equipment inside the TB, including the MSIVs, while hurricane winds are assumed to never reach a velocity that would significantly damage the TB.

19.1.5.4.1.3 Risk-Significant Functions and Features

Listed below are key ESBWR design features and functions identified in the PRA report, Revision 6, that significantly reduce the expected CDF associated with tornado and hurricane strikes that produce an extended LOPP as compared to the CDF for operating BWR designs from tornadoes and hurricanes. The risk-significant functions of the following features are primarily the same as those identified for LOPP for internal events:

- The ESBWR design stores a significant amount of water over the core that is available for gravity-driven core cooling. This is not true for most operating BWRs.
- The exterior walls of the ESBWR RB are generally thicker than those of the RBs of operating BWRs.
- The ICs in the ESBWR are wholly contained inside the reactor building, and the exterior walls surrounding the ICs are generally thicker than the walls protecting ICs at older operating BWRs.
- The ESBWR long-term DHR design relies on more robust dc power as compared to operating reactors, where safety-related dc power generally will last only 4 to 8 hours. Such power will last 72 hours in the ESBWR design.
- Long-term core cooling for extended loss of offsite power events for the ESBWR design depends in great part on gravity injection rather than the turbine-driven pumps on which most operating BWRs depend.
- The ESBWR design has dedicated refill lines for the ICs unlike older operating BWRs with ICs.
- The ESBWR ICs store a larger water supply per megawatt over the core than do older plants with ICs.

- The ESBWR design has eliminated or reduced many contributors to CDF resulting from extended loss of offsite power. This has resulted in the CCF of digital I&C systems becoming an important contributor in hurricane-induced CDF. While the CCF of digital I&C systems is a larger contributor to CDF as a percentage at the ESBWR than at operating plants, the absolute value of the contribution to CDF from this source is similar for operating and ESBWR designs.
- For the ESBWR design, hurricanes should have no possibility of significantly damaging seismic Category I, seismic Category II, or RTNSS structures.
- The FPS components located outside the RB that are needed for FAPCS makeup (this system provides long-term makeup to the pools in the RB that cool the reactor) are designed to seismic Category I standards and can withstand tornado missiles and other natural phenomena such as hurricanes.

19.1.5.4.1.4 Significant At-Power Sequences and Leading Contributors

The CCFs of the following SSCs are significant for high-winds events based on the reported risk achievement worth (RAW) values (all near or in excess of 400) in Table 14.6-4 in the PRA report, Revision 6:

- Containment vacuum breakers
- Containment vacuum breaker isolation valves
- Inverters in the uninterruptible ac power supply
- Batteries in the dc power system
- IC heat exchangers
- Logic units in the DPS
- DPVs
- GDCS injection valves
- IC condensate return valves
- Check valves in the GDCS
- Software
- DPS processors
- Air-operated scram valve no. 126
- Control rods insertion
- DPS load drivers

Of the top 50 cutsets for high-winds events, four were caused by tornado-induced LOPP. The rest were caused by hurricane-induced LOPP.

The top 30 hurricane-induced cutsets identified the following important SSCs and human actions as contributing to core damage:

- Software CCF
- CCF of check valves in the GDCS
- CCF of DPVs
- Control rods failure to insert
- Failure of any SRV to reclose following ATWS
- Failure of squib valves
- Operator failure to inject using the FPS or a fire truck

- Operator failure to recognize need for depressurization
- Operator failure to recognize need for low-pressure makeup after depressurization

19.1.5.4.2 Regulatory Criteria

In Section 19.1 of this report, the staff considered the results and insights from the high-winds risk assessment with respect to the Commission's objectives for new reactor designs.

No specific regulatory requirements govern the safety insights used to support design certification.

However, the staff used applicable guidance from SRP Section 19.0, Revision 2 in its review.

19.1.5.4.3 Staff Evaluation

In Revision 4 of the PRA report, the applicant modified the data it used in the high-winds risk assessment and reevaluated the risk. Because of this, most of the staff's RAIs relating to high winds, which referenced Revision 3 of the PRA report and were described in the staff's SER with open items, are no longer pertinent to the high-winds assessment. This report specifically discusses RAIs that do pertain to the assessment presented in the PRA report, Revision 5.

19.1.5.4.3.1 *Tornado Hazard Frequency*

The staff confirmed that the applicant appropriately used the data and methodology from NUREG/CR-4461, Revision 1, for estimating tornado strike frequencies. To ensure that the strike frequency was bounding for most sites in the United States, the applicant used frequencies generated from data for the central region of the United States, which is the region of the country with the highest occurrence rate of tornadoes and the highest tornado intensities.

19.1.5.4.3.2 *Evaluation of the Effects of Tornado Strikes*

The ESBWR high-winds risk analysis makes assumptions in its tornado risk assessment. The staff reviewed these assumptions and finds them to be reasonable for estimating the CDF associated with tornadoes damaging an ESBWR design.

The staff reviewed the at-power LOPP event tree to determine whether the systems, associated support systems, and structures housing the systems and support systems were appropriately credited for tornado-strike events. The staff finds the applicant's LOPP event tree appropriate for evaluating tornado strikes, given the assumptions made in the PRA. The staff's review supports the applicant's conclusion that the expected CDF from tornadoes is very low because of: (1) the robustness of the seismic Category I and II structures, (2) the low frequency of tornado occurrence, and (3) the low conditional probabilities associated with a tornado actually hitting an ESBWR site.

19.1.5.4.3.3 *Hurricane Hazard Frequency*

To estimate the frequency of hurricane strikes, the applicant averaged the frequency of hurricane-induced loss of offsite power at nuclear power plants located on shorelines and in areas with high hurricane return rates in Florida, Louisiana, and North Carolina during a 19-year period. The staff finds that this estimate of hurricane strikes is bounding for most sites in the United States, with the possible exception of particular coastal sites along the Gulf Coast or the

Atlantic Ocean coast from North Carolina southward. The staff confirmed that the applicant used the data from NUREG/CR-6890, Volume 1, for estimating hurricane strike frequencies. In response to RAI 19.1-185, the applicant modified the PRA report, Revision 5, to state that, if site-specific high-winds frequencies are estimated to be greater than the frequencies in the PRA, then the COL applicant should perform a departure analysis and apply the appropriate measures. Therefore, RAI 19.1-185 is resolved.

19.1.5.4.3.4 *Evaluation of the Effects of Hurricane Strikes*

The staff's review evaluated the assumption that seismic Category I, seismic Category II, and RTNSS structures are essentially undamaged by hurricanes, and reviewed the LOPP event tree to determine whether the systems (and associated support systems and structures housing the systems and support systems) are appropriately credited for hurricane strike events.

The high-winds assessment assumes that it is impossible for Category 4 or Category 5 hurricanes to significantly damage equipment in seismic Category I or Category II buildings in a manner that can cause core damage. In RAI 19.1-169, the staff asked the applicant to explain its basis for this assumption. RAI 19.1-169 was tracked as an open item in the SER with open items. In response, the applicant referred the staff to the response to RAI 19.1-167, which stated that the buildings were built to withstand design-bases seismic events and therefore were assumed to be able to withstand high winds. The staff found this response insufficient and, in RAI 19.1-169 S01, asked the applicant to provide an engineering basis to explain why there is zero probability that hurricanes or tornados can damage seismic Category I or II structures. The staff later supplemented the RAI and asked the applicant to address the possibility of design flaws or construction errors that might lead to weaknesses in the as-built design that would make the plant vulnerable to such tornado missiles or winds. In response, the applicant again provided a deterministic explanation rather than a probabilistic one. The rationale was presented in terms of margins of forces designed for versus forces expected. The staff found this an unacceptable response.

In RAI 19.1-169 S02, the staff again requested the applicant to either (1) provide a probabilistic defense for its use of seven orders of magnitude reduction in risk that provides an engineering basis for the reduction that links the strengths of the design to specific numerical analyses (e.g., fragility curves) that address conditional probabilities of failure, or (2) provide qualitative arguments as to why high winds do not constitute outliers in risk, qualitative arguments why high winds do not challenge the NRC's safety goals, a discussion of why the risk from high-winds events is lower than for operating plant designs, and a list of safety insights that are important for the as-built, as-operated plant to follow to ensure that the assumptions in the high-winds risk analysis are true and remain valid during the lifetime of the plant. The staff noted that a qualitative analysis would not constitute a PRA, and COL applicants may need to address high winds on a plant-specific probabilistic basis if the Commission has a high-winds risk assessment standard in place 1 year before the first fuel load.

In response, the applicant provided fragility curves, including statistical parameters for the lognormal curves representing the fragilities, for one- and three-story concrete buildings based on gust windspeeds over the range of hurricane windspeeds of 33.5 to 134.1 m/s (75 to 300 mph). The applicant stated that the three-story fragility curve is characteristic of the ESBWR RB, but did not supply any basis for this claim. In its response, the applicant referenced a paper on the fragility of concrete reinforced structures to hurricane winds, but was unable to answer staff questions about the basis for the fragility curves. The staff independently contacted the author of the paper and clarified the basis of the fragility curves cited by GEH. Clarification of

how the author determined the fragility curves (i.e., based on actual damage to concrete structures due to hurricanes) leads the staff to conclude that the fragility values are conservative. In addition, the staff discussed the robust nature of reinforced concrete structures and their ability to withstand high winds with structural experts within the NRC to confirm the insights drawn from the fragility curves. Based on this evaluation, the staff concurs in the assumption that seismic Category I and II structures have an extremely low conditional probability of catastrophic failure due to hurricane winds. Therefore, RAI 19.1-169 and the associated open item are resolved.

The staff finds the applicant's LOPP event tree appropriate for evaluating hurricane strikes given the assumptions made in the PRA. The staff finds that the applicant's conclusion that the expected frequency of a hurricane strike resulting in core damage is very low to be reasonable. This is because of (1) the robustness of the seismic Category I, seismic Category II, and RTNSS structures, and (2) placement of pumps, diesel generators, and large water tanks that are capable of refilling the tanks over the core in robust structures.

19.1.5.4.3.5 High Winds—General

The applicant concluded in Revision 4 of the PRA report that the CDF resulting from high winds was not a significant contributor to ESBWR core damage risk. The staff questioned this conclusion in RAI 19.1-181. In response, the applicant indicated that it would modify the PRA to state that the high-winds at-power risk assessment does not produce significant core damage sequences or insights that differ from the internal events at-power LOPP results. The applicant is to make a similar modification for shutdown events (i.e., with regard to RAI 19.1-182). The staff finds these responses acceptable. Therefore, RAI 19.1-181 and RAI 19.1-182 are resolved.

19.1.5.4.3.6 Risk Assessment Limitations

The risk assessment did not appear to evaluate the effect of damage from a hurricane or tornado strike to unprotected equipment located out in the open (e.g., fire hydrants), and the staff asked for clarification of this issue in RAI 19.1-168. The staff was tracking RAI 19.1-168 as an open item in the SER with open items. In response, the applicant stated that the PRA credits the FPS with providing makeup water to the IC/PCCS pool and water for reactor water coolant/inventory control. The response stated that the supporting equipment for these functions is to be seismic Category I or II. In addition, makeup and inventory control function independently of the fire suppression function (i.e., yard hydrant and piping).

In a followup to this question and in conjunction with the review of the FAPCS, the staff noted in RAI 9.1-16 S02, that there were apparent inconsistencies in the level of protection afforded FAPCS makeup regarding tornado missiles. The staff also documented its concern about fire hydrants, standpipes, or other large lines that could be attached at some point to the dedicated portion of the FPS connection to the FAPCS for makeup. In response, the applicant stated that the FPS components located outside the RB that are needed for FAPCS makeup will be designed to seismic Category I standards and will be designed to withstand tornados and other natural phenomena. The dedicated line from the FPS to the FAPCS is not designed to NFPA standards and will not fulfill a fire protection function. Fire hydrants, standpipes, or other large lines will not be attached to the dedicated portion of the FPS designed to provide long-term makeup to pools in the RB. In response to RAI 9.1-16 S03, the applicant committed to place these attributes in Tier 2 of the DCD. Therefore, RAI 19.1-168 and the associated open item are resolved.

In its review of Revision 6 to the DCD, the staff found that it could not distinguish, in the Tier 1 figures, the seismic Category I line that will have no firefighting requirements placed on it and will only be used for refill of the pools as an RTNSS backup. In RAI 9.1-142, the staff asked the applicant to identify the dedicated line on Figure 2.16.3-1 in Tier 1 of the DCD. In response, the applicant concurred that the FPS simplified diagrams illustrated in DCD Tier 2, Revision 6, Figure 9.5-1 and DCD Tier 1, Revision 6, Figure 2.16.3-1 should be enhanced to reflect the dedicated, seismic Category I FPS piping that aligns the primary diesel-driven fire pump to the FAPCS isolation lines that provide makeup to the IC/PCCS pools and the spent fuel pool (SFP). The applicant stated it would modify in Revision 7 to the DCD the simplified diagrams in DCD Tier 2, Figure 9.5-1, and DCD Tier 1, Figure 2.16.3-1, to reflect separate seismic Category I piping routed from the fire pump enclosure (FPE) to the RB supplying redundant FAPCS connections to IC/PCCS pools and SFP makeup. The applicant indicated that this piping run will be routed in a seismic Category I trench from the FPE to the RB FAPCS manual isolation valves. The staff finds this acceptable and confirmed that Revision 7 to the DCD was modified as stated by the applicant. Therefore, RAI 9.1-142 is resolved.

The PRA report, Revision 2 and DCD Tier 2, Revision 5, had contradictory statements about the effect on RTNSS structures from tornado missiles (including tornado missiles from EF2 and EF3 tornadoes). The staff raised this issue in RAI 19.1-167. The staff was tracking RAI 19.1-167 as an open item in the SER with open items. In response, the applicant clarified how it performed the high-winds risk assessment. However, the modifications provided in the PRA report, Revision 3, appeared to the staff to continue to contradict DCD Tier 2, Revision 5, Section 3.3, and the applicant's response to RAI 19.1-167, dated March 8, 2008. Upon reading the augmented Section 14.5.1 of the PRA report, Revision 3, which estimates CDF due to the impact of high winds on the ESBWR SSCs, it appeared to the staff that Tables 14.3-1 (see Table 19.1-12 in this report) and 14.3-2, "ESBWR Tornado Wind—PRA Predicted Structure Damage," implied that seismic Category II structures will suffer no significant damage from EF4 or EF5 tornadoes. Furthermore, neither the table nor the surrounding text made direct mention of tornado missiles and their effect on SSCs.

In addition, Section 14.4.1, "Tornado Strike Frequency," in the PRA report, Revision 3, in a discussion about the strike frequency for EF4 and EF5 tornadoes when the reactor is at power, stated that "EF4/EF5 tornado windspeeds would exceed the design of RTNSS and NS structures, but not seismic Category I or seismic Category II structures. Therefore, for EF4 and EF5 tornadoes, the equipment located in RTNSS structures and the yard will be assumed to fail." There was no mention of the effect tornado missiles would have on seismic Category II structures. In RAI 19.1-167 S01, the staff requested clarification of how the risk assessment included the effects of these tornado missiles. In response, the applicant stated the following:

For the purpose of the ESBWR NEDO-33201, Revision 3 high winds risk analysis, component failures associated with extreme winds and missiles for EF4 and EF5 tornadoes were treated similarly. This assumption was made to reduce the complexity of the analysis and also because only a small number of seismic Category II components were credited.

Key assumptions related to tornado missiles and the ESBWR high-winds risk analysis include the following:

- Only components located at or above grade are considered to be vulnerable to tornado missile damage.

- Components classified as seismic Category I or located within a structure designated as seismic Category I are not susceptible to damage from tornado missiles.
- Components not classified as seismic Category I or not located within a structure designated as seismic Category I are susceptible to damage from tornado missiles.
- While the seismic Category II components are designed to withstand the extreme winds associated with EF5 tornados and are designed to withstand EF4 tornado missiles, they are not designed to withstand EF5 tornado missiles.

The staff finds that this explanation adequately clarifies the issue. Therefore, RAI 19.1-167 and the associated open item are resolved.

The risk assessment takes credit for systems providing long-term heat removal from the core, but did not provide sufficient information on the structures that house these systems and their support systems. In particular, the staff was interested in aboveground outdoor tanks or other structures holding significant quantities of liquids, such as water or oil, that if failed or damaged could cause a flooding issue for other important equipment on site (e.g., pumps, transformers). The staff raised this issue in RAI 19.1-166. The staff was tracking RAI 19.1-166 as an open item in the SER with open items. In response, the applicant provided assurance that the ESBWR flooding analysis considered the potential for important equipment to be flooded by aboveground outdoor tanks or other fluid-holding structures. The staff finds this explanation sufficient. Therefore, RAI 19.1-166 and the associated open item are resolved.

19.1.5.4.4 Conclusion

Based on its review of the high-winds risk assessment, the staff finds the risk assessment to be technically adequate to support design certification and the identification of risk insights. The extremely low absolute values estimated for the expected CDF from these events is indicative of the applicant's design and engineering efforts to reduce risk outliers and known limitations in former BWR designs.

The ESBWR high-winds CDF accounts for the duration (in hours) of operation in Modes 5 and 6 per outage and the anticipated calendar outage frequency of one refueling outage every 2 years. Therefore, the staff believes the high-winds CDF can be added to the full-power internal events CDF.

**Table 19.1-11. ESBWR Tornado Wind—PRA Assumed Structure Damage
(Summary of Table 14.3-2 from the PRA Report, Revision 6).**

TORNADO CATEGORY	ESBWR PLANT STRUCTURES ^a			
	SC I	SC II	RTNSS	NS
EF0	No Damage	No Damage	No Damage	No Damage
EF1	No Damage	No Damage	No Damage	No Damage
EF2	No Damage	No Damage	No Damage	Failure
EF3	No Damage	No Damage	No Damage	Failure
EF4	No Damage	No Damage	Failure	Failure
EF5	No Damage	Failure from Tornado Missiles	Failure	Failure

a. The ESBWR plant structures are identified as seismic Category I (SC I), seismic Category II (SC II), regulatory treatment of nonsafety systems (RTNSS), and nonseismic (NS).

**Table 19.1-12. ESBWR Hurricane Wind—PRA Assumed Structure Damage
(Summary of Table 14.3-1 from the PRA Report, Revision 6).**

HURRICANE CATEGORY	ESBWR PLANT STRUCTURES ^a			
	SC I	SC II	RTNSS	NS ^b
Category 1	No Damage ^c	No Damage	No Damage	No Damage
Category 2	No Damage	No Damage	No Damage	No Damage
Category 3	No Damage/ LOPP	No Damage/ LOPP	No Damage/ LOPP	Failure
Category 4	No Damage/ LOPP	No Damage/ LOPP	No Damage/ LOPP	Failure
Category 5	No Damage/ LOPP	No Damage/ LOPP	No Damage/ LOPP	Failure

b. The ESBWR plant structures are identified as seismic Category I (SC I), seismic Category II (SC II), regulatory treatment of nonsafety systems (RTNSS), and nonseismic (NS).

c. This column excludes the turbine building, service water building, and electrical building, which are assumed to be undamaged by either hurricanes or their missiles.

d. The applicant assumed that the only impact to the site from Category 1 and 2 hurricanes would be an LOPP with no additional equipment failures caused by the hurricane. The internal events PRA addresses these LOPP events, which have been included under the initiating events for LOPP.

19.1.6 Safety Insights from the Probabilistic Risk Assessment for Other Modes of Operation

19.1.6.1 *Results and Insights from Internal Events Low-Power and Shutdown Operations Probabilistic Risk Assessment*

19.1.6.1.1 Summary of Technical Information

19.1.6.1.1.1 *Methodology and Approach*

This shutdown risk evaluation encompasses plant operation in cold shutdown and refueling modes, as discussed in TS Modes 5 and 6. Mode 5 begins when the reactor coolant temperature in the RCS drops to or below 93.3 degrees C (200 degrees F) while the plant is cooling and shutting down. For Mode 5, the reactor mode switch is in the shutdown position. Before entering Mode 5 from Mode 4, the heat removal requirements are transferred to the RWCU/SDC system. The main condenser and circulating water pumps are removed from service and use of the ICs is terminated. For the entire duration of Mode 5, all DHR is through the RWCU/SDC system. Mode 6 begins when one or more of the reactor vessel head closure bolts is less than fully tensioned.

The applicant assessed the following four plant operational states (POSSs) during Modes 5 and 6: Mode 5, Mode 5 (Open), Mode 6 (Unflooded), and Mode 6 (Flooded), as previously defined in DCD Tier 2, Revision 9, Chapter 16. Fuel is in the reactor vessel during each of these POSSs.

GEH did not quantitatively evaluate operation in Mode 4 (i.e., stable shutdown in which the RCS temperature is less than 215 degrees C [420 degrees F] and greater than 93.3 degrees C [200 degrees F]). In this mode, the reactor mode switch is in the shutdown position and control rod insertion is completed. The initial RPV conditions (pressure and temperature) for Mode 4 are the same as the power-operating values.

The scope of the shutdown PRA (PRA Report) is that of a Level 1 PRA. The different accident sequences are characterized according to whether the core is damaged or not.

The critical safety functions essential to the shutdown model are DHR and inventory control. Containment is assumed to be open. The TS for Modes 5 and 6 do not require containment integrity. GEH did not quantitatively assess the safety functions of spent fuel cooling and reactivity control. The applicant stated that the spent fuel cooling function will be maintained during shutdown modes just as it will be during full-power modes. The applicant assumed this function to have no significant impact on the shutdown model. Regarding reactivity control, all control rods are fully inserted for the duration of the modeled modes; therefore, ATWS is not an issue. DCD Tier 2, Revision 9, addresses reactivity control during shutdown deterministically.

19.1.6.1.1.2 *Significant Accident Sequences and Leading Contributors*

The applicant estimated the mean shutdown CDF from internal events to be 1.7×10^{-8} /yr. This is a very low CDF in comparison to CDF estimates for plants currently operating. This low value represents the applicant's effort to reduce or eliminate the contributors to core damage found in previous PRAs through improvements in plant design. However, areas of shutdown risk for which modeling is least complete or nonexistent (such as operator errors of commission and

rare/new initiating events) could become important contributors to risk and cause the CDF for plant-specific implementations or the ESBWR design to be higher.

The ESBWR shutdown CDF accounts for the duration (in hours) of operation in Modes 5 and 6 per outage and the anticipated calendar outage frequency of one refueling outage every 2 years. Therefore, the staff believes the shutdown CDF can be added to the full-power internal events CDF.

The analysis assumed that all evaluated shutdown core damage events would result in a large release because of the potential for the containment to be open during the outage. CCFP is not affected because the containment is not being used as a mitigating system during shutdown. Thus, the applicant reported the shutdown LRF from internal events to be $1.7 \times 10^{-8}/\text{yr}$.

Three initiating events that may occur during each of the four POSs (Mode 5, Mode 5 [open], Mode 6 [unflooded], and Mode 6 [flooded]) comprise over 80 percent of the ESBWR internal events shutdown CDF. These three initiating events include LOCAs in the RWCU/SDC lines below TAF, LOCAs in instrument lines below TAF, and RPV leaks and diversions caused by operator error. For LOCAs below TAF, manual closure of the LDW hatches is required to prevent core damage, since it is necessary to flood the drywell and the vessel up to a level above TAF to ensure core cooling. For RPV leaks and diversions in which the GDSC fails to provide automatic injection to the RCS, the significant operator actions include isolating the RWCU system and providing low pressure makeup following RCS depressurization.

LOPPs from severe weather events, grid failures, or switchyard faults contribute another 10 percent to the total internal events shutdown CDF. Losses of both trains of the RWCU/SDC system contribute 8 percent to the total internal events CDF.

19.1.6.1.2 Acceptance Criteria

No specific regulatory requirements govern the safety insights used to support design certification. However, the staff used applicable guidance from SRP Section 19.0, Revision 2 in its review. In addition, the staff used the risk insights gained from SECY-97-168, "Issuance for Public Comment of Proposed Rulemaking Package for Shutdown and Fuel Storage Pool Operation," and guidance provided in the associated SRM. The staff considered the results and insights for shutdown risk assessment with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report.

19.1.6.1.3 Staff Evaluation

19.1.6.1.3.1 *Evaluation of Methodology and Approach*

The staff evaluated the ESBWR internal events shutdown PRA by reviewing the results reported in Section 16, "Shutdown Risk," of the PRA report, through Revision 6. To evaluate GEH's decision to not quantitatively evaluate Mode 4, the staff reviewed the TSs and concluded that all credited systems in the PRA have the same TS for Modes 1 through 4, except for containment. Mode 4 requires containment integrity, but the containment is de-inerted, limiting the plant's ability to control hydrogen generation following a severe accident. The duration of this mode is assumed to be 8 hours. The applicant stated that the CDF contribution of Mode 4 is bounded by the full-power PRA. Chapter 8.1.4 of the ESBWR full-power PRA, Revision 6, assesses the LRF contribution from this mode. To mitigate a high wind event, the plant will go to Mode 4 and will not de-inert in Mode 4 when the plant shuts down in anticipation of a hurricane strike. This

risk insight is captured in DCD Tier 2, Revision 9, Chapter 19, Table 19.2-3. The staff finds this PRA modeling of Mode 4 to be acceptable.

The scope of the shutdown PRA is that of a Level 1 PRA. The different accident sequences are characterized according to whether the core is damaged or not. The earliest versions of the PRA did not define core damage. In RAI 19.1-96, the staff requested additional information documenting the success criteria used in the shutdown PRA. The staff tracked RAI 19.1-96 as an open item in the SER with open items. In two responses the applicant documented T-H uncertainty for short term and long term core cooling in Mode 5 in the ESBWR shutdown PRA using MAAP 4.06. Consideration of these results led to changes in the shutdown event trees/success criteria. The applicant changed the shutdown event trees and success criteria to include the addition of depressurization using four DPVs in Mode 5 LOCAs, with the exception of LOCAs in the feedwater lines. The applicant also changed the PRA success criteria to require one GDCS injection line from each of the two GDCS pools and one GDCS equalizing line. The applicant also provided the results of MAAP 4.0.6 calculations for the loss of RWCU/SDC event to support the success criteria of needing two SRVs to implement low-pressure injection. The applicant also stated that the shutdown PRA core damage definition is consistent with RG 1.200. The staff finds this RAI response and the associated changes to the shutdown event trees and success criteria to be acceptable. Therefore, RAI 19.1-96 is resolved.

In RAI 5.4-59, the staff raised questions regarding the capability of the RWCU/SDC system to operate successfully during Modes 5 and 6. The staff requested that the normal vessel levels for RWCU/SDC operation in all modes, including Modes 5 and 6, be documented in DCD Tier 2. The staff also requested calculations that show the temperatures and levels at which the RWCU/SDC systems can adequately remove decay heat in Modes 4, 5, and 6 (with the RPV head installed), including any minimum and maximum levels. In addition, the staff asked the applicant to explain how coolant from the RWCU/SDC system flows and mixes within the vessel and within the shroud. The staff was concerned that coolant from the RWCU/SDC system heat exchanger could bypass the core region and therefore not provide the cooling capacity predicted in the GEH model. The staff tracked RAI 5.4-59 as an open item in the SER with open items.

In response, GEH updated DCD Tier 2, Revision 6, Section 5.4.8.2.2, regarding the need to maintain RPV water level sufficiently above the first stage water spillover point in the steam separators. To avoid a thermal stratification condition, the applicant expects that the plant will be operated with the RPV water level sufficiently above the minimum level assumed during use of the RWCU/SDC system. The applicant also updated DCD Tier 2, Revision 6, to discuss the mixing between the incoming cooler shutdown water and the spillover water from the separators. In response, the applicant provided the results of a study of the relationship between the mixing factor and the RWCU/SDC flow rates. The applicant also stated that the RWCU/SDC pump flow and NRHX cooling capacity are designed to limit the temperature difference between the supply and return flows, thereby minimizing the potential for thermal cycling stress.

The staff performed audit calculations of the RWCU/SDC flows using computational fluid dynamics (CFD) to assess the applicability of the GEH approach. The applicant completed CFD predictions for two sets of conditions to predict the flow and mixing of the RWCU/SDC fluid during Mode 5 (shutdown) conditions in the ESBWR. The predictions demonstrate that the cooling system flow mixes well with the overall natural circulation flow in the system. These simulations confirm the applicability of the complete mixing assumption in the GEH model. The

two CFD predictions have different flow rates and temperature differences and indicate slightly different overall flow patterns. In both cases, however, the mixing is essentially complete. The staff considers the issue of adequate coolant mixing from the RWCU/SDC during shutdown operation resolved based on the information provided by GEH and the results of the staff's independent calculations. Therefore, RAI 5.4-59 is resolved.

In response to the follow-up activities identified by the staff during an audit of the PRA May 6-8, 2009 (ADAMS Accession Number, ML103420463), GEH modified the RWCU/SDC breaks outside containment event trees in Revision 4 of the PRA to include an additional top event—four DPVs actuate before GDCS actuation. This modification makes the RWCU/SDC breaks outside containment trees consistent with the RPV leak and diversion event trees, which the applicant had previously modified. GEH also proposed a revision to Section 22 of the PRA report, entitled, “ESBWR PRA Changes,” to include an evaluation of the modified trees by quantifying the new sequences that were generated. The new logic does not bring in any new changes to system models. The new sequences generated an additional CDF/LRF contribution of 0.012 percent of the baseline internal events shutdown CDF. The changes do not impact the shutdown external event models (fire, flood, and high-winds analyses) and their associated focused PRA evaluations. The new sequences have no impact on the shutdown external events models, since the shutdown external events initiators do not follow the RWCU breaks outside containment sequences. The staff finds the resolution of this issue (i.e., assessing the impact of the tree changes with limited amount of requantification) to be acceptable only for the purposes of identifying risk insights to support design certification.

Based on key risk insights from SECY-97-168; NUMARC 91-06, “Guidelines for Industry Actions to Assess Shutdown Management”; and previous shutdown PRAs, the staff's review of the ESBWR shutdown PRA considered shutdown TS, critical operator actions, and proposed regulatory oversight for nonsafety systems identified by the RTNSS process. In SECY-97-168, the staff concluded that the current level of shutdown safety was achieved through the use of voluntary measures (including those identified in NUMARC 91-06). In light of these insights, the staff was concerned that GEH did not identify outage planning and control consistent with NUMARC 91-06 as a key risk insight in DCD Tier 2, Revision 4, Table 19.2-3. In RAI 19.1-149 S01, the staff asked GEH to address this issue. The staff tracked RAI 19.1-149 as an open item in the SER with open items. In response, GEH added outage planning and control consistent with NUMARC 91-06 as a key risk insight in DCD Tier 2, Revision 5, Table 19.2-3. Therefore, RAI 19.1-149 is resolved.

As discussed previously, RWCU/SDC drainline breaks below TAF and instrument line breaks below TAF that may occur during each of the four POSs (Mode 5, Mode 5 [Open], Mode 6 [Unflooded], and Mode 6 [Flooded]) comprise a large fraction of the ESBWR internal events shutdown CDF. The LDW is equipped with a personnel hatch and an equipment hatch to allow access to the containment. These hatches are closed during normal operation but may be open during refueling. Closure of these two hatches is required for successful drywell flooding and to prevent core damage following a break below TAF. Manual closure of the LDW hatches is a risk-significant operator recovery action.

The RTNSS program includes closure of the LDW hatches, which is described in the Availabilities Control Manual. The ability to close the hatch is covered during Modes 5 and 6. Immediate action is required if hatch closure is unavailable for any reason. The staff noted that Revision 3 of the PRA report stated that the availability control (AC) was applicable in Mode 5 and 6 during operations with the potential for draining the reactor vessel. Since Revision 3 of the PRA report indicated that LOCAs involving pipe breaks contributed over 98 percent of the

shutdown CDF, the staff believes that the applicability of this AC to Modes 5 and 6 should extend during the entire outage period. In response to RAI 19.1-123 S01, GEH changed AC 3.6.1, "Lower Drywell Hatches," described in DCD Tier 2, Revision 4, Section 19A, to require applicability in Modes 5 and 6 during the entire outage period. Since the entire duration of Modes 5 and 6 is covered by AC 3.6.1, this update is acceptable.

However, the staff noted that Availability Control Surveillance Requirement (ACSR) 3.6.1.2 and ACSR 3.6.2.3, whose purpose is to verify—with a frequency of 30 days—that, during an outage, the LDW equipment hatch and personnel airlock can be secured, are inconsistent with NUMARC 91-06 guidance and operating experience. GEH responded that the intent of AC 3.6.1 is to allow the licensee to mitigate the effects of a pipe break in a line from the vessel below TAF. AC 3.6.1 provides administrative controls that allow the licensee to establish a boundary to flood the LDW to above the level of the break, thus ensuring that the fuel in the core is covered with water.

GEH stated that the ACs are not intended to satisfy NUMARC 91-06 recommendations for preventing fission product release from containment. The staff believes that this guidance should have to satisfy the NUMARC 91-06 recommendations. The NUMARC 91-06 guidelines state, "a procedure should be established to assure that closure can be accomplished in a time commensurate with plant conditions," recognizing that conditions change during the outage. Containment closure is necessary to prevent fission product release from containment during severe accidents initiated by pipe breaks below TAF. The ACSR frequency of 30 days in the ESBWR PRA is most likely longer than the outage itself and may not provide closure of containment sufficient to prevent a fission product release. In RAI 19.1-123 S02, the staff requested that GEH address this issue. The staff tracked RAI 19.1-123 as an open item in the SER with open items.

In response, GEH stated that ACSR 3.6.1.2 and ACSR 3.6.1.3 augment ACSR 3.6.1.1, which requires verification every 12 hours that the LDW hatch administrative closure plan is in place. The administrative closure plan, as outlined in the availability control limiting condition for operation (ACLCO) bases, provides for "administrative controls [that] assure trained personnel will be continuously located in the area of the doors and appropriate administrative controls are in place to communicate awareness of potential breaches and effect decisions to secure the hatches." The staff finds that this administrative control, verified to be in place every 12 hours, satisfies the intent of the NUMARC 91-06 guideline that states, "[a] procedure should be established to assure that closure can be accomplished in a time commensurate with plant conditions," and recognizes that conditions change during the outage. Therefore, RAI 19.1-123 is resolved.

ACSR 3.6.2.2 and ACSR 3.6.2.3 require verification that the equipment hatch and airlock can be secured in place. The component capability to be secured in place is not expected to be compromised at any point in time, and the continuous attention of trained personnel provides adequate assurance of the continued capability. A 30-day periodic reverification constitutes an additional formal documented assurance of what is otherwise continuously verified. The staff finds these ACSRs to be an acceptable means of addressing the intent of NUMARC 91-06.

Once a postulated LOCA has been detected, the plant operator must correctly diagnose the situation, make the decision to close the hatches, gain access to the -6,400-mm (-21-ft) level in the RB, and manually close the equipment hatch and the personnel airlock. Two key assumptions substantiate the human reliability estimates: (1) outage personnel will be continuously located in the area of the doors and (2) closure of both the equipment hatch and

personnel hatch can be done from outside the LDW/containment. GEH did not recognize Item 1 as a key risk insight in DCD Tier 2, Revision 4, Table 19.2-3. The ability to close the equipment and personnel hatch from the outside is a key design feature necessary to support hatch closure reliability estimates. GEH did not document this design insight as a key risk insight in DCD Tier 2, Revision 4, Table 19.2-3. In RAI 19.1.0-4 S01, the staff requested GEH to address this issue. RAI 19.1.0-4 S01, contained Parts A through F. The staff tracked RAI 19.1.0-4 S01, Parts A through F as open items in the SER with open items. Closure of RAI 19.1.0-4 S01, Parts A through F, and the closure of the associated open items are discussed below.

In response to RAI 19.1.0-4 S01, Part A, GEH stated that at least 90 minutes will be available to detect, diagnose, and close the hatches. Thus, GEH maintained that outage personnel do not need to be located in the area of the doors continuously. However, GEH added, "closure of both the equipment hatch and the personnel hatch can be done from outside the lower drywell/containment" as a key risk insight in DCD Tier 2, Revision 5, Table 19.2-3. As previously discussed, in response to RAI 19.1-123 S02, GEH noted that ACSR 3.6.1.2 and ACSR 3.6.2.3 augment ACSR 3.6.2.1, which requires verification every 12 hours that the LDW hatch administrative closure plan is in place. The administrative closure plan (as outlined in the ACLCO bases) provides for "administrative controls [that] assure trained personnel will be located in the area of the doors continuously and appropriate administrative controls are in place to communicate awareness of potential breaches and effect decisions to secure the hatches." The staff finds this approach to be reasonable because the ACLCO bases discusses controls that assure trained personnel will be located in the area of the doors continuously. Therefore, RAI 19.1.0-4 S01, Part A, is resolved.

To mitigate losses of RWCU/SDC, RPV leaks, and LOCAs in Mode 5 and Mode 5 (Open), with the exception of feedwater line breaks, four DPVs must open for the GDCS to function. The shutdown PRA models the success of the GDCS, assuming that all eight DPVs will be operable and will automatically open. During the initial review of the ESBWR TS, the staff found that there was no requirement for the DPVs to automatically open, and there was no requirement for the DPVs or the SRVs to be operable in Modes 5 and 6. Instead, there was only a TS surveillance requirement to have a proper vent path for GDCS operability. The TS did not specify the size of this vent path or the number of valves. The staff was concerned that the complex task of determining an adequate size vent path was being left as an operational activity to be completed without the support of engineering analysis.

Furthermore, Revision 3 of the PRA did not model the failure of the operator to determine the adequate RCS vent path size (number of DPVs that need to be opened) to support GDCS operation. This operator error cannot be modeled with conventional human reliability assessment methodologies. The staff stated these issues in RAIs 19.1-93, 19.1-94, 19.1-95, 19.1-96 S01, and 19.1-143 and tracked them as open items in the SER with open items. In response, GEH updated the TS in DCD Tier 2, Revision 5, for the GDCS to require six out of eight DPVs to be operable for automatic actuation until the reactor head is removed. Therefore, RAIs 19.1-93, 19.1-94, 19.1-95, and 19.1-143 are resolved.

In RAI 19.1-96 S02, the staff raised the concern that if only four DPVs are available and one of the four DPVs fails to open, then the GDCS function fails. The staff requested GEH to perform and document a sensitivity study assuming only four DPVs were available and operable for GDCS. In their response to RAI 19.1-96 S02, technical specifications were updated to require six out of eight DPV valves to be operable until the vessel head is removed. Additionally, GEH provided a sensitivity study showing the shutdown PRA results with varying DPV requirements.

The staff reviewed the updated technical specifications based on the results of the sensitivity analyses and finds them to be acceptable. Therefore, RAI 19.1-96 is resolved.

As shown in Table 16.6.3 of the ESBWR shutdown PRA, the top 12 dominant cutsets contribute over 64 percent of the risk. These cutsets initiate by a LOCA below TAF or an operator-induced leak or diversion in each of the four POSs—Mode 5, Mode 5 (Open), Mode 6 (Unflooded), and Mode 6 (Flooded).

In DCD Tier 2, Revision 6, Section 19.2.4.2, GEH stated that it judged the offsite consequences from shutdown risk to be negligible since significant shutdown events occur during Mode 6, which does not begin until approximately 96 hours after shutdown. In RAI 19.1-159, the staff requested that GEH revise this statement based on two assumptions. In Section 16 of the PRA, over 40 percent of the internal shutdown CDF occurs in Mode 5. Furthermore, NUREG/CR-6595, “An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events,” issued January 1999, states the following on page 4-3:

The results indicate that [for] source terms which involve a release of about 10 percent or less of the core iodine inventory (10% iodine releases are associated with early fatalities in accidents that occur at full-power), offsite doses generally fall below the early fatality threshold approximately 8 days or less after shutdown.

Based on these assumptions, the staff believes that the consequences of a shutdown severe accident occurring during Modes 5 and 6 approximately 8 days or less after shutdown are not negligible. The staff tracked RAI 19.1-159 as an open item in the SER with open items. In response to RAI 19.1-159, GEH revised Section 19.2.4.3 of DCD Tier 2, Revision 6, to state the following:

The source terms for containment bypass events may not fall below the early fatality threshold until approximately 8 days after shutdown; however, the frequency of shutdown containment bypass events is very low. As a result the offsite consequences, which are the product of the source term risk and the shutdown containment bypass frequency, are not significant.

Since this DCD modification is consistent with NUREG/CR-6595, the staff finds this DCD change to be acceptable. Therefore, RAI 19.1-159 is resolved.

19.1.6.1.3.2 *Evaluation of Risk-Significant Functions/Features, Phenomena/Challenges, and Human Actions*

Listed below are key ESBWR design features that significantly reduce the shutdown CDF as compared to the CDF for operating BWR designs. These design features are addressed below by initiating event category.

19.1.6.1.3.2.1 Operator-Induced Draindowns/Loss-of-Coolant Accidents

The ESBWR design has reduced the number of potential RPV drain pathways caused by postulated system misalignment during shutdown conditions. As compared to residual heat removal (RHR) systems in current BWRs, the RWCU/SDC system in the ESBWR does not have the potential to divert RPV inventory to the suppression pool through the suppression pool suction, return, or spray lines. The RWCU/SDC system does not provide any drywell spray function, so the potential for draining the RPV through drywell spray does not exist. In addition,

the applicant eliminated recirculation lines in the ESBWR design, further reducing potential RPV drainpaths.

Although the RWCU/SDC system design has been improved to reduce the number of potential RPV drain pathways, it still has the potential to drain the RPV during Modes 5 and 6. The system is connected to the RPV during shutdown and used to discharge excess reactor coolant to the main condenser or to the radwaste system during startup, shutdown, and hot standby conditions.

The RWCU/SDC system containment penetrations have redundant and automatic power-operated containment isolation valves that close upon signals from the leakage detection and isolation system in Modes 5 and 6. In Modes 5 and 6, TS 3.3.6.3 and 3.3.6.4 require the RWCU/SDC system and the FAPCS containment isolation valves to close on low reactor vessel water level (Level 2). These risk-significant TS protect against postulated breaks in the RWCU/SDC system outside containment.

Breaks outside containment can originate only in RWCU/SDC system piping because this is the only system that removes reactor coolant from the containment in Mode 6. The rest of the RPV piping is isolated. The RWCU/SDC system containment penetrations have redundant and automatic power-operated containment isolation valves that close on signals from the leak detection and isolation system.

An additional, diverse nonsafety isolation of the RWCU/SDC system provides protection in the event of a break outside containment. This additional, diverse nonsafety isolation signal of the RWCU/SDC system protects the system in Modes 1 through 4, but is not required by the TS for shutdown modes. This signal, provided by the DPS, is not credited during Modes 5 and 6 in the shutdown PRA. The staff raised this concern in RAI 19.1-178. In response, concerning the omission of TS for DPS in Mode 5, GEH updated the PRA model in Revision 4 of the PRA report to include RWCU/SDC breaks outside containment. At the PRA audit, the staff reviewed the associated event trees and found that they had logic errors. The licensee evaluated the impact of these logic errors in Section 22.16, Shutdown Risk, of the PRA, Revision 3. In Section 22.16 of the PRA, the event trees were modified to include a top event for four DPVS actuating prior to GDCS actuation. The risk contribution from the new sequences was also quantified. The staff concludes that the additional core damage sequences have a negligible impact on the baseline results. Based on the information provided in Section 22.16 of the PRA and the applicant's response, RAI 19.1-178 is resolved.

Regarding penetrations in the vessel bottom head upstream of the RWCU/SDC isolation valves, GEH did not quantitatively evaluate operator-induced loss of reactor vessel inventory in Revision 3 of the PRA. In RAI 19.1.0-4 S01, Part E, the staff asked GEH to address this issue by adding key risk insights to the DCD. In response, GEH discussed the ESBWR design requirements that preclude the need for freeze seals. To minimize the use of freeze seals, maintenance valves are installed on power-operated equipment and valves on lines attached to the RPV that require maintenance. Because these maintenance valves facilitate maintenance on power-operated equipment and valves on lines attached to the RPV, freeze seals will not be required (see DCD Tier 2, Revision 9, Section 5.2.3.1.1). This is acceptable. However, GEH did not fully address piping penetrations in the vessel bottom head upstream of the isolation valves.

In RAI 19.1.0-4 S02, Part E the staff requested that GEH (1) provide information about the sizes of these piping penetrations and associated alarm or position indication in the control room or

(2) model operator-induced leaks using operating data in the shutdown PRA. In response, GEH evaluated operator-induced leaks in Revision 4 of the PRA. The staff reviewed the associated event trees, cutsets, and risk insights and finds them to be acceptable. Therefore, RAI 19.1.0-4 S01 and S02, Part E, are resolved.

To reduce the likelihood of the reactor vessel inventory being drained into the feedwater lines, the RWCU/SDC lines returning to the feedwater lines are each provided with redundant check valves in series, which are located in the main steam tunnel. A single, power-operated isolation valve in each line is located upstream of the check valves and inside the RB. The FAPCS and CRDS connections are downstream of the two check valves. A postulated break in the RWCU/SDC piping system inside the RB, which would otherwise allow reactor coolant to flow backwards through the main feedwater lines and spill into the RB, will be isolated by either the redundant RWCU/SDC check valves or the feedwater check valves, even assuming a single failure of one check valve.

GEH evaluated the draining of the RPV during FMCRD maintenance but did not consider it to be a shutdown PRA initiating event. If the operator were to inadvertently remove the control rod after the FMCRD is out, without first installing the temporary blind flange, or conversely, if the operator were to inadvertently remove the FMCRD after first removing the control rod, an unisolable opening in the bottom of the reactor would be created, resulting in drainage of reactor water. The possibility of inadvertent reactor drain down by this means is considered remote for the following reasons:

- Procedural controls similar to those of current BWRs provide the primary means for prevention. Current BWR operating experience demonstrates the acceptability of this approach. There has been no instance of an inadvertent drain down of reactor water caused by simultaneous CRD and control rod removal.
- During drive removal operations, personnel are required to monitor the bottom of the RPV for water leakage out of the CRD housing. Abnormal or excessive leakage occurring after a partial lowering of the FMCRD within its housing indicates the absence of the full metal-to-metal seal between the control rod and control rod guide tube required for full drive removal. In this event, the FMCRD can then be raised back into its installed position to stop the leakage and allow corrective action.

In the PRA, GEH stated that the COL applicant will develop maintenance procedures with provisions to prohibit coincident removal of the control rod and CRD of the same assembly. In addition, GEH stated that the COL applicant will develop contingency procedures to provide core and spent fuel cooling capability and mitigation actions during CRD replacement with fuel in the vessel. However, the staff noted that GEH did not capture these risk insights in DCD Tier 2, Revision 4, Table 19.2-3. In RAI 19.1.0-4 S01, Part B, the staff requested that GEH address this issue. The staff was tracking RAI 19.1.0-4 as an open item in the SER with open items. In response to RAI 19.1.0-4 S01, Part B, GEH added these assumptions of DCD Tier 2, Revision 5, Table 19.2-3. Therefore, RAI 19.1.0-4 S01, Part B, is resolved.

Should a LOCA or an operator-induced loss of inventory occur while all active nonsafety-related systems are unavailable, or, if the operator fails to initiate injection after successful manual RPV depressurization, the passive GDCS will automatically inject water into the RPV.

19.1.6.1.3.2.2 Loss of Both Operating Reactor Water Cleanup/Shutdown Cooling Trains

At the beginning of every shutdown outage, both RWCU/SDC trains are assumed to be running, with the pumps varying their speed to meet the cooldown rate objectives. The shutdown PRA also assumes that both trains are running during Modes 5 and 6; however, only one train is required to prevent reactor coolant boiling. More importantly, the focused PRA results, which were used to identify nonsafety-related systems for RTNSS, assumed that both trains of the RWCU/SDC system are running until the reactor cavity is flooded. To ensure that the focused PRA results remain valid, operation of both trains of the RWCU/SDC system during Modes 5 and 6 is an important risk insight that GEH did not capture in DCD Tier 2, Revision 4, Table 19.2-3. In RAI 19.1.0-4 S01, Part C, the staff requested that GEH address this issue. In response to a different RAI, RAI 19.2-121 S01, GEH updated Table 19.2-3 of DCD Tier 2, Revision 6, to state that, “during shutdown conditions, in preparation for refueling, both trains of RWCU/SDC are running while the unit is in either Mode 5 or Mode 6 until the reactor cavity is flooded.” The staff considers this issue to be resolved because the applicant has documented in the DCD that two trains would be running. Therefore, RAI 19.2-121 and RAI 19.1.0-4 S01, Part C, are resolved.

The RWCU/SDC function may fail for any of the following reasons:

- Failure of both RWCU/SDC trains
- Isolation of the RWCU/SDC system caused by RPV low-level or leakage detection and isolation system signals
- LOPP
- Loss of RCCWS or PSWS

Should any of these scenarios occur, the ICs, which offer an alternative, automated, passive, core-cooling path not available in current operating BWRs, can cool the ESBWR.

TS 3.3.5.3 and 3.3.5.4 require the ICS to be operable in Mode 5. The ICS automatically initiates upon high reactor vessel steam dome pressure, low reactor vessel water—Level 2, and low-low reactor vessel water—Level 1. In RAI 19.1-144 S01, the staff raised a question regarding the effect of noncondensable gases on ICS performance during Mode 5. The staff tracked RAI 19.1-144 in the SER with open items. In response to RAI 19.1-144 S04, GEH responded that the ESBWR has an RPV head vent system that handles any noncondensable gas buildup that could inhibit natural circulation core cooling. The piping is 50.8 mm (2 inches) in diameter. After the plant reaches cold shutdown, the two valves in the vent piping leading to the equipment and floor drain sump are opened and the valve in the piping connected to the main steamline is closed. GEH stated in the proposed revision to the PRA that the head vent should not impact the ICS operability because the isolation of this line is considered very likely. Based on T-H analyses, the operator has 32 hours to close the head vent if the ICS is started manually without credit for CRD and 14.5 hours if the ICS starts automatically without credit for CRD flow. The operators in the MCR can diagnose an open head vent line because the isolation valves leading to the equipment and floor drain sump have open and closed indication and down steam temperature indication in the MCR. Based on this update to the PRA, the staff considers RAI 19.1-144 to be resolved.

Should the ICS fail, three FAPCS functions (coolant injection, suppression pool cooling, and backup SDC) are included within the scope of RTNSS at shutdown. In the unlikely event that these functions fail, the ESBWR design has a second, automated, passive core-cooling path via the GDCS. The GDCS is required to be operable and automatically initiates upon reactor vessel water level (Level 1), during Modes 5 and 6, except when the new fuel pool gate is open and the water level exceeds 7.01 m (23.0 ft) over the top of the RPV flange. Section 19.1.6.1.3.1 of this report discusses adequate venting for the GDCS during shutdown.

19.1.6.1.3.3 *Evaluation of Insights from Uncertainty and Importance Analyses*

The staff used the results of the applicant's importance analyses to identify (1) SSCs or human actions or both whose reported reliability contribute most to achieving the low reported shutdown CDF (i.e., RAW), and (2) SSCs or human actions or both whose reported reliability would contribute most to a reduction in shutdown CDF if the reliabilities were improved (i.e., risk reduction worth).

Since the reported ESBWR shutdown CDF is very low and clearly meets the Commission's safety goals and the EPRI ALWR CDF requirements, the staff focused on the results of the GEH risk achievement worth analyses. The staff used these results to identify (1) the SSCs for which it is particularly important to maintain the reliability and availability levels assumed in the PRA (e.g., by testing and maintenance) to avoid significant increases in CDF and (2) the human actions that, if they were to fail, would have the largest impact on the shutdown PRA.

GEH performed risk importance analyses at the component/human action/initiating event level. Revision 3 of the PRA did not evaluate breaks outside containment, which were therefore excluded from the importance analyses. Breaks outside containment can originate only in the ICS, RWCU/SDC system, FAPCS piping, or instrument lines, which are the only systems that remove reactor coolant from the containment during shutdown. The rest of the RPV vessel piping is isolated. The RWCU/SDC system, FAPCS, and ICS containment penetrations have redundant and automatic power-operated, safety-related containment isolation valves that close upon signals from the leakage detection and isolation system in Modes 5 and 6.

In Revision 3 of the PRA report, GEH stated that the high reliability of the leakage detection and isolation system provides the basis for the screening of (1) shutdown LOCAs outside of containment and (2) operator-induced losses of reactor vessel inventory during shutdown. Therefore, the high reliability of the leakage detection and isolation systems is a key risk assumption, but GEH did not document it as a key risk insight in Table 19.2-3 of DCD Tier 2, Revision 4. In RAI 19.1.0-4 S01, Part D, the staff requested that GEH address this issue. RAI 19.1.0-4 S01, Part D, was tracked as an open item in the SER with open items. In response, GEH updated the PRA model in Revision 4 to model operator-induced leaks and RPV diversions. The staff finds the information added to the PRA report to be acceptable. Therefore, RAI 19.1.0-4 S01, Part D, is resolved.

The staff noted that TS were omitted for DPS in Mode 5. The staff raised this concern in RAI 19.1-178. In response to RAI 19.1-178, GEH updated the PRA model in Revision 4 to include RWCU/SDC breaks outside containment. At the PRA audit, the staff reviewed the associated event trees and found that they had logic errors. The licensee evaluated the impact of these logic errors in Section 22.16, Changes to the Shutdown PRA Model, of the PRA. In Section 22.16 of the PRA, the event trees were modified to include a top event for four DPVS actuating prior to GDCS actuation. The risk contribution from the new sequences was also quantified. The staff concluded that the additional core damage sequences have a negligible

impact on the baseline results. Based on the information provided in Section 22.16 of the PRA and the applicant's response, RAI 19.1-178 is resolved.

Based on the addition of RPV leaks and diversions and breaks outside containment to Revision 4 of the shutdown PRA, the risk achievement worth analyses yielded additional risk insights. LOCAs below TAF in each of the four POSs have the highest RAW values, exceeding 5×10^5 . LOCAs below TAF comprise 50 percent of the internal shutdown CDF/LRF. To prevent core damage, the operator must close the drywell hatch.

Events having RAW values exceeding 1×10^3 include the following:

C63-CCFSOFTWARE	Common-cause failure of software, which represents the failure of the entire safety-related Q-DCIS platform to actuate all supported functions, including manual actuations
%M6U_RWCU_BOC	LOCAs involving RWCU break outside containment in Mode 6 (Unflooded)
%M5_LOCA_OT	LOCAs in lines other than feedwater or GDCS in Mode 5
%M5O_LOCA_OT	LOCAs in lines other than feedwater or GDCS in Mode 5 (Open)
%M5_LOCA_FW	LOCA in feedwater line—Mode 5
%M6U_LOCA_FW	LOCA in feedwater line—Mode 6 (Unflooded)
%M5_LOCA-G	LOCA in GDCS—Mode 5
%M5 LOCA-FW	LOCA in feedwater—Mode 5 (Open)

19.1.6.1.3.4 Evaluation of Insights from Sensitivity Studies

GEH also performed a number of sensitivity studies to gain insights about the impact of uncertainties on the reported shutdown CDF. Specifically, these studies show how sensitive the shutdown CDF is to potential biases in numerical estimates assigned to initiating event frequencies, equipment unavailability, and human error probabilities.

Similar to the full-power analysis, GEH performed two separate analyses to investigate the impact of shutdown operation without credit for nonsafety-related, defense-in-depth systems. The focused PRA sensitivity study evaluates whether passive systems alone are adequate to meet the Commission's safety goals of less than 1×10^{-4} /yr for CDF and less than 1×10^{-6} /yr for LRF. The focused PRA retains the same initiating event frequencies as the baseline PRA and sets the status of nonsafety-related systems to failed, while safety-related systems remain unchanged in the model.

19.1.6.1.3.4.1 Focused Probabilistic Risk Assessment Sensitivity

The intent of the focused PRA is to determine the impact to CDF and LRF caused by removing credit for nonsafety systems. The results are then compared to the following NRC criteria to determine whether systems should be considered for some form of regulatory treatment:

- CDF less than $1 \times 10^{-4}/\text{yr}$
- LRF less than $1 \times 10^{-6}/\text{yr}$

GEH performed focused PRA analyses for the following shutdown PRA models:

- Internal
- Fire
- Flood
- High winds

The shutdown analyses do not require evaluation of LRF because the containment is assumed to be open, and therefore LRF equals CDF.

The following systems are assumed to be unavailable for the focused analyses: emergency diesel generators, condenser, condensate and feedwater, CRD injection and FMCRD, FAPCS, RWCU/SDC, FPS injection, DPS, MSIV, RCCWS, TCCWS, plant air, nitrogen, PSWS, FMCRD groups, and PIP buses A3 and B3. To perform the focused and RTNSS sensitivity studies for shutdown internal events, fires, floods, and high winds, the applicant generated two flag files: (1) fail all nonsafety systems and (2) fail all nonsafety systems except those systems designated as RTNSS.

PRA report Tables 11.3-36, 11.3-37, 11.3-38, and 11.3-39 show the results of the focused PRA analyses and the RTNSS PRA analyses for shutdown internal events, fire, floods, and high winds. The focused internal events shutdown sensitivity analysis generated a CDF of $1.69 \times 10^{-6}/\text{yr}$, and the RTNSS study generated a CDF of $4.41 \times 10^{-7}/\text{yr}$. Based on the CDF results for the shutdown focus sensitivities, the NRC goal of $1 \times 10^{-4}/\text{yr}$ CDF is met for both the shutdown focus and RTNSS sensitivities. Since all shutdown CDF sequences are assumed to be direct LRF contributors, the LRF goal of $1 \times 10^{-6}/\text{yr}$ is applicable as well. The RTNSS LRF meets the threshold, but the shutdown focus exceeds the LRF threshold. The difference in CDF showed a decrease of about a factor of four. A review of risk-significant events from the RTNSS shutdown results highlights the importance of the FPS/FAPCS injection pathway.

The focused shutdown fire study generated a CDF of $2.87 \times 10^{-6}/\text{yr}$. The RTNSS study generated a CDF of $3.91 \times 10^{-7}/\text{yr}$. Based on the CDF results for the shutdown fire focused sensitivity analysis, the NRC goal of $1 \times 10^{-4}/\text{yr}$ CDF is met for both the baseline fire and RTNSS scenarios. Since all shutdown CDF sequences are assumed to be direct LRF contributors, the LRF goal of $1 \times 10^{-6}/\text{yr}$ is met for the RTNSS case, but exceeded in the case of the focused shutdown fire. The RTNSS results show a risk reduction of 88 percent as compared to the results of the focused study. Similar to the shutdown internal events RTNSS results, the focused fire study shows that the FPS/FAPCS injection pathway is risk significant.

The focused shutdown flood study generated a CDF of $6.35 \times 10^{-7}/\text{yr}$ and the RTNSS study generated a CDF of $2.81 \times 10^{-7}/\text{yr}$. Based on the shutdown flood focused sensitivity study, the NRC goals of 1×10^{-4} CDF and $1 \times 10^{-6}/\text{yr}$ LRF are met. The RTNSS results show a risk reduction of approximately 56 percent as compared to the focused results. Similar to the shutdown internal events RTNSS results, the focused flood study shows that the FPS/FAPCS injection pathway is risk significant.

The focused shutdown high-winds study generated a CDF of $1.20 \times 10^{-6}/\text{yr}$ for tornados and hurricanes, and the RTNSS study generated a CDF of $1.71 \times 10^{-7}/\text{yr}$ for tornados and hurricanes. The results for the focused high-winds sensitivity showed significant impact to CDF, with the

failure of nonsafety systems in both the RTNSS and focused cases. The RTNSS results indicate a CDF reduction of approximately 86 percent as compared to the focused case. Similar to the shutdown internal events RTNSS results, the focused high-winds study shows that the FPS/FAPCS injection pathway is risk significant.

19.1.6.1.3.4.2 Loss-of-Coolant Accident Frequency Sensitivity

Because of the lower temperatures and pressures in the RPV during shutdown, GEH applied a reduction factor to the LOCA frequencies for the shutdown PRA. Section 16.3.1.2.1 of the ESBWR shutdown PRA documents the basis for the reduction. This sensitivity case shows the following CDF/LRF results with no reduction factor applied.

- Baseline results = 1.63×10^{-8} /yr
- Sensitivity results = 9.42×10^{-8} /yr

The CDF/LRF for the sensitivity increases by a factor of eight as compared to the baseline results since LOCAs constitute 50 percent of the baseline results. Thus, the shutdown PRA results depend on the LOCA frequencies and how they are determined. However, without the reduction factor, the ESBWR shutdown CDF results are still below the NRC safety goals.

19.1.6.1.3.4.3 Lower Drywell Hatch Sensitivity

RWCU/SDC drainline breaks below TAF and instrument line breaks below TAF that may occur during all four POSs comprise about 50 percent of the ESBWR internal event shutdown CDF/LRF. For the breaks below TAF, it is necessary to flood the drywell and the vessel up to a level above the TAF to reach a safe core-cooling condition. Failure to close the LDW equipment hatch and the personnel air lock following a postulated LDW LOCA is assumed to lead to core damage.

The PRA evaluates two hatch closure events. For instrument line LOCAs, GEH estimated that 6 hours would be available to close the hatch. For RWCU drainline breaks, GEH estimated that 90 minutes would be available. Both times are based on the worst-case pipe break scenario.

The baseline case used screening values for the operator action to close the hatch. A failure probability of 0.01 was applied to the case in which 6 hours would be available for the action. A failure probability of 0.1 was applied to the case in which 90 minutes would be available.

GEH ran a sensitivity case applying a 50-percent failure rate for both hatch closure events. The resulting CDF/LRF is 3.48×10^{-7} /yr. The resulting ESBWR shutdown CDF and LRF increased by almost a factor of 20, indicating that the operator's ability to reliably close the drywell hatches is risk significant.

GEH also ran a sensitivity case assuming that no LDW entry is allowed until Mode 6. This eliminates the Mode 5 and Mode 5 (Open) sequences that include drywell hatch closure. The ESBWR shutdown CDF and LRF are approximately 26 percent of the baseline value of 1.25×10^{-8} /yr.

19.1.6.1.3.4.4 Operator Action Sensitivity

During shutdown, the plant relies on operator actions for accident mitigation more than it does during power operation. Several systems have no automatic actuation and rely on operators to

initiate (i.e., FPS, FAPCS, CRD). Human actions are the only barrier between the initiating events and core damage for LOCA events below TAF. The operator must close the equipment and personnel hatches to allow the drywell to flood, which will prevent core damage. GEH evaluated the two operator action sensitivity cases discussed below.

Case 1 sets all recovery actions to TRUE (failed). This eliminates several systems from possible accident mitigation because CRD (during shutdown), FAPCS, FPS, and manual depressurization depend completely on human action for initiation. The RWCU/SDC system also requires operator action following LOPP. Most importantly, the operator's ability to close the equipment and personnel hatches following a LOCA was also set to TRUE (failed).

The resulting CDF/LRF for Case 1 is 5.76×10^{-6} /yr. Case 1 results show an increase of more than two orders of magnitude in CDF over the baseline case. For the LOCA below TAF, with the operator failing to close the equipment and personnel hatch, these sequences go directly to core damage. Therefore, for these initiating events, the CDF value is equal to the initiating event value.

Case 2 assigns all recovery actions a low human error probability of 1×10^{-3} . This human error probability estimate is about one order of magnitude lower than most modeled human actions. It shows how the CDF could be affected if credit is taken for very effective operator response to transients.

The resulting CDF for Case 2 is 1.14×10^{-9} /yr. Case 2 results in a decrease in CDF of approximately one order of magnitude when compared to the base shutdown case. Human errors still dominate the top cutsets in this case. Even with the reduced failure rates, human errors remain generally higher than the common-cause equipment failures that appear in the top cutsets. Based on these sensitivity studies, the staff concludes that the ESBWR shutdown risk is sensitive to human error.

19.1.6.1.3.4.5 Reactor Pressure Vessel Draindown Initiating Event Frequency Sensitivity

The initiating event frequency for RPV draindown events used in the ESBWR shutdown PRA analysis is lower than the initiating event value developed in EPRI 1003113. The use of the lower frequency is based on design improvement of the ESBWR RWCU system compared to current BWR RHR systems, as well as a review of the RWCU piping and instrumentation drawings. This sensitivity case shows the following results with the initiating event frequency developed by EPRI (i.e., 2.80×10^{-5} per hour) applied to the shutdown PRA sequences:

- Baseline Results = 1.63×10^{-8} /yr (with a truncation limit of 1×10^{-14} /yr)
- Sensitivity Results = 2.58×10^{-8} /yr

The shutdown CDF increases when using the initiating event frequency developed by EPRI for RPV draindown events. The CDF increases by nearly 58 percent over the baseline shutdown case. RPV leaks account for about 30 percent of the CDF in the base case. These leaks represent by far the largest contribution after LOCA events. In this sensitivity case, CDF contribution from draindown events increases to 56 percent. Although there is a notable increase in CDF with the EPRI value, the results are still within the NRC stated goals for CDF and LRF.

GEH stated that the basis for the reduced frequency of a draindown event is reasonable. The RWCU system has very few possible leak or diversion paths (non-LOCA) and almost all are

small lines under 50.8 mm (2 in.). A review of the incidents used to develop the EPRI value showed that very few of the events are relevant to the ESBWR design.

GEH also mentioned that the risk associated with draindown events (especially in Mode 6) may be overestimated. The cases with the largest contribution are generally Mode 6 (Unflooded) cases in which the RWCU system is isolated, but no alternate DHR source is successful. These cases account for about 21 percent of the overall baseline CDF. In these cases, no credit is taken for water in the pools above the vessel or fire pump hoses in the RB. In these cases, the vessel head and the containment head are removed, and the RPV is open to the refueling floor of the RB. Makeup to the reactor well/RPV would be available from one or several of the pools in the RB. This would require operators opening a valve to cross-connect the pools to the reactor well. FPS pumps pumping to these pools, or a FPS pump truck connected to the building, could also provide additional water to the vessel in these scenarios. The analysis took no credit for these potential inventory sources.

19.1.6.1.4 Conclusion

Based on the discussions above, the staff concludes that the methodology and approach of the internal events low-power and shutdown risk analysis are technically adequate to identify risk insights to support design certification. However, the applicant modified the RWCU/SDC breaks outside containment event trees to include an additional top event involving the actuation of four DPVs before GDACS actuation. This modification makes the RWCU/SDC breaks outside containment trees consistent with the RPV leak and diversion event trees, which the applicant modified in Revision 4 of the PRA. GEH submitted a proposed revision to Section 22 of the PRA report evaluating the modified trees by quantifying the new sequences that were generated. The new logic does not bring in any new system model changes. The new sequences generated an additional CDF/LRF contribution of 0.012 percent of the baseline internal events shutdown CDF. Since the shutdown external events initiators do not follow the RWCU break outside containment sequences, the new sequences added have no impact on the shutdown external events models. The staff finds the resolution of this issue to be acceptable for the purposes of identifying risk insights to support design certification.

19.1.6.2 *Results and Insights from External Events Low-Power and Shutdown Operations Probabilistic Risk Assessment*

Based on the Level 1 internal events shutdown PRA, GEH performed a quantitative fire, flood, and high-winds risk analysis. Using the MIN-MAX method, GEH also conducted an SMA. This section briefly summarizes the methodology used to complete each assessment and discusses the significant severe accident sequences and leading contributors.

19.1.6.2.1 Results and Insights from the Low-Power and Shutdown Fire Risk Assessment

19.1.6.2.1.1 *Summary of Technical Information*

19.1.6.2.1.1.1 Methodology and Approach

Based on the Level 1 internal events shutdown PRA, GEH performed a quantitative fire risk assessment.

The applicant performed the ESBWR full-power fire assessment according to the guidance in NUREG/CR-6850. The guidance in NUREG/CR-6850 is not applicable to qualitative screening

for shutdown conditions. Therefore, the GEH performed the screening for the shutdown fire model assuming that the postulated fire has to result in one of the initiating events defined in the shutdown model. The critical safety functions essential to the shutdown model are DHR and inventory control. The applicant assumed that reactivity control and SFP cooling would have no significant impact on the shutdown model. Power availability is modeled for its impact on DHR. Loss of power is evaluated as an initiating event, and the model includes power dependencies for systems.

Fire-induced IORV is also not a shutdown fire-initiating event. Line breaks, or a stuck-open relief valve, that occur above the reactor vessel water level (i.e., Level 3) mark are not initiating events because RWCU/SDC system operation is not expected to be impacted. Similar to the internal events shutdown PRA, all evaluated shutdown fire core damage events are assumed to result in a large release because of the potential for the containment to be open during the outage.

As in the full-power fire assessment, GEH conservatively assumed that fires would propagate unmitigated in each fire area and damage all functions in the fire area with a few exceptions. Fire suppression is not credited. During shutdown conditions, a fire barrier may not be intact because of maintenance activities. The shutdown fire analysis assumes that all barriers are intact, or an added fire watch would increase the probability of fire detection and suppression and also help to restore the fire barrier in time to prevent fire propagation.

19.1.6.2.1.1.2 Shutdown Fire Risk Significant Core Damage Scenarios and Dominant Contributors

This section describes the top two sequences contributing over 90 percent of the shutdown fire risk, as reported by GEH. Shutdown Fire Scenario 1, contributing approximately 51 percent, is initiated by a postulated fire in the TB general area (F4197 fire area) during Mode 5, Mode 5 (Open), and Mode 6 (Unflooded) operation. This fire is assumed to result in a complete failure of the service air system because of cable failures, which lead to the closure of all RWCU containment isolation valves outside the containment. Other systems failed by a postulated fire in F4197 include the condensate and feedwater system, TCCWS, service air system, and UPS buses in the TB and other places. These failures make fire area F4197 a significant risk contributor to the shutdown fire risk.

The cabling for the RCCWS and PSWS is assumed not to be failed by a fire in F4197 since these two systems have been identified as part of the RTNSS program. The design requirements for RTNSS ensure that a postulated fire would not damage both trains.

Shutdown Fire Scenario 2, contributing approximately 42 percent of the CDF, is initiated by a postulated fire in the switchyard (fire area F7300). A fire in the switchyard is conservatively assumed to result in loss of DHR. The transfer from the offsite power to diesel generators is assumed not to be fast enough to prevent the failure of the RWCU system. The analysis assumes no recovery of offsite power.

19.1.6.2.1.1.3 Risk-Significant Function/Design Feature, Phenomena/Challenges and Human Actions for the Shutdown Fire Assessment

A fire in the MCR will not result in a shutdown initiator. The ESBWR MCR is designed differently from the traditional MCR. The ESBWR MCR controls are connected to the back panel rooms via fiber optic cables, which are unaffected by an MCR fire. The loss (including

melting) of the cables or visual display units will not cause inadvertent actuations or affect the automatic actions associated with safety and nonsafety equipment.

To limit spurious actuations of safety-related equipment, the hard wires are minimized to control the consequences of a postulated fire. From the DCIS rooms to the components, fiber optics will also be used up to the RMUs in the plant. Hard wires are then used to control the subject components. Typically, two load drivers are actuated simultaneously to actuate the component. To eliminate spurious actuations, these two load drivers are located in different fire areas. Therefore, by design, a fire in a single fire area cannot cause spurious actuation of safety-related equipment.

Regarding the treatment of fires in primary containment during shutdown, the small quantity of combustible materials and spatial separation is assumed to prevent damage to the redundant divisional circuits in this area. During shutdown, the primary containment is deinerted. The Level 2 PRA considers deinerted operation before and following shutdown, as described in Section 8.1.4 of the PRA report, Revision 4.

19.1.6.2.1.2 Acceptance Criteria

No specific regulatory requirements govern the safety insights used to support design certification. However, the staff used applicable guidance from SRP Section 19.0, Revision 2, in its review.

The staff considered the results and insights for shutdown risk assessment with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report.

19.1.6.2.1.3 Staff Evaluation

GEH assumed the probability of a fire barrier failure to be 7.4×10^{-3} . In RAI 19.1-126 S01, the staff requested that GEH submit information describing which fire barriers are particularly risk significant and how the COL applicant will choose between roving and continuous fire watches for barriers of increased risk significance. The staff tracked RAI 19.1-126 as an open item in the SER with open items.

In Revision 2 of the PRA, GEH performed sensitivity studies to evaluate the risk impact of fire barrier failure associated with a fire watch. GEH analyzed the following two cases of fire barriers for the shutdown fire PRA:

- (1) Only one fire barrier exists on the fire propagation path where the fire barrier is a fire door.
- (2) Only one fire barrier exists on the fire propagation path where the fire barriers are walls or sealed penetrations. Multiple barriers in series exist on the fire propagation path.

In response to RAI 19.1-126 S01, GEH updated Revision 3 of the PRA report and provided the following risk insights in Table 19.2-3 of DCD Tier 2, Revision 5:

During shutdown conditions, a continuous fire watch is required for the following scenarios with breached fire barriers for maintenance activities:

- The breaching of the fire door between fire areas F1152 and F1162 (the RB fire areas that house RWCU pumps).

- The simultaneous breach of the multiple fire barriers that can open fire areas F3301 and F3302 (the N-DCIS room fire areas) to the fire area F3100 (the corridor fire area) at the same time.

The risk insights added to Table 19.2-3 of the DCD regarding risk significant fire barriers are acceptable to resolve the staff's concern. Therefore, RAI 19.1-126 is resolved.

In Revision 4 of the PRA report, with the changes in fire area designations, GEH updated the shutdown fire barrier sensitivity studies as reported in Tables 11.3-49 and 11.3-50 of the PRA. GEH then updated DCD Tier 2, Revision 6, Table 19.2-3, to include continuous fire watches for additional fire areas as follows:

During shutdown conditions, a continuous fire watch is required for the following scenarios with breached fire barriers for maintenance activities:

- The breaching of the fire doors between fire areas F1152 and F1162 (the RB fire areas that house RWCU pumps) and between fire areas F4250 and F4260 (the TB fire areas that house the RCCW pumps).
- The simultaneously breaching of the multiple fire barriers that can open fire areas F3301 and F3302 (the N-DCIS room fire areas) to fire area F3100 (the corridor fire area) at the same time.
- The simultaneously breaching of the multiple fire barriers that can open fire areas F5350 and F5360 (the PIP electric equipment room fire areas) to fire area F5100 (the corridor fire area) at the same time.

Based on the GEH updates to the PRA and to Chapter 19 of DCD Tier 2, Revision 6, the staff's concerns associated with the identification of risk significant fire barriers are resolved.

Since NUREG/CR-6850 excludes low power/shutdown operations, the applicant calculated the shutdown fire ignition frequencies using a different method. The estimation of fire ignition frequencies for shutdown conditions is performed using the information provided in the RES/OERAB/S02-01, "Fire Events—Update of U.S. Operating Experience, 1986 - 1999." This document expands and updates the information of AEOD/S97-03, "Special Study: Fire Events - Feedback of U.S. Operating Experience," issued June 1997. RES/OERAB/S02-01 summarizes information on fire events that occurred during power operation and during shutdown conditions and estimates fire frequencies in both power and shutdown operation for different types of buildings and locations.

To compare the shutdown fire risk with the full-power fire risk, the shutdown fire initiating event frequencies are converted from shutdown year to calendar year. Table 12.7-7 in the PRA Report, Revision 4, calculates the conversion factors for each mode by assuming a 2-year refueling cycle and an outage duration of 548 hours. Therefore, the shutdown fire initiating event frequency calculations assume one-half shutdown per year (274 hours). The total CDF for all shutdown fire scenarios is $9.56 \times 10^{-9}/\text{yr}$.

To understand MCR fire risk, the staff, in RAI 19.1-129 S01, requested a sensitivity study that credits only automated equipment or information in the PRA regarding the operator's ability to monitor the RWCU/SDC system status, reactor vessel water level, and RCS pressure from the back panel rooms. The staff also requested an AC to prevent both remote shutdown panels

from being out of service at the same time or administrative controls that would prevent both shutdown panels from being out of service at the same time. The staff tracked RAI 19.1-129 as an open item in the SER with open items. In response to RAI 19.1-129 S01, the applicant clarified that the MCR fire scenario is modeled with credit only for automated equipment by assuming all operator actions failed except the manual scram. The applicant also explained that for the shutdown PRA models, a fire in the MCR will not result in an initiating event. Under the modeled shutdown conditions (Modes 5 and 6), the reactor has been successfully cooled down with the RWCU/SDC system running automatically. The applicant also stated that Technical Specification Section 3.3.3.1 provides the operability control for the remote shutdown system. The response to RAI 19.1-129 explains the operability of automated equipment during MCR fire scenarios, in which GEH stated that the ESBWR MCR controls are connected to the back panel rooms via fiber optic cables, which are unaffected by a postulated MCR fire. The loss (including melting of the cables or visual display units) will not cause inadvertent actuations or affect the automatic actions associated with safety and nonsafety equipment. GEH also added that it had evaluated fires in the back panel rooms separately and considered their impact on the operability of automatic systems. In addition, DCD Tier 2, Revision 6, Table 19.2-3, states that the communication links between the MCR and the Q-DCIS and N-DCIS rooms do not include any copper or other wire conductors that could potentially cause fire-induced spurious actuations that could adversely affect safe shutdown. Based on the applicant responses and these updates to the DCD, the staff's concerns regarding a postulated MCR fire and its impact on safety and nonsafety-related equipment are resolved. Therefore, RAI 19.1-129 is resolved.

Regarding fires in the drywell/containment area, this area was screened from the shutdown fire assessment. GEH assumed that a fire in the drywell/containment area is highly unlikely to result in the loss of the RWCU/SDC system. The RWCU system inboard containment isolation valves are located in the LDW, which could, according to GEH, be well separated spatially. GEH also believes that minimal combustible fuel loads will be located inside the LDW. Screening of a postulated drywell/containment fire that could result in a loss of the RWCU/SDC system and the RWCU inboard containment isolation valves is risk significant. GEH did not identify spatial separation of the RWCU containment isolation or limiting combustible loading in the drywell containment area as a key risk insight in DCD Tier 2, Revision 4, Table 19.2-3. In RAI 19.1.0-4 S01, Part F, the staff requested that GEH address this issue.

In response to RAI 19.1.0-4 S01, Part F, GEH stated that drywell/containment fires that could result in loss of the RWCU/SDC and the RWCU inboard containment isolation valves were screened as not significant based on spatial separation of these valves. GEH also stated that this is a level of detail that is consistent with many design features that, although important, are not expected to change and are not considered to be significant assumptions. This response did not address the staff's concern. In RAI 19.1.0-4 S02, Part F, the staff requested GEH to document as a key risk insight that drywell/containment fires that could result in loss of the RWCU/SDC and the RWCU inboard containment isolation valves were screened based on spatial separation of the RWCU, or to assess and quantify drywell/containment fires that could result in loss of the RWCU/SDC and the RWCU inboard containment isolation valves in the ESBWR fire PRA.

In response to RAI 19.1.0-4 S02, Part F, GEH added the screening of LDW fires (ones that can impact the RWCU/SDC system and the RWCU isolation valves) to DCD Tier 2, Revision 6, Table 19.2-3, as a key risk insight based on physical separation of the components, the limited number of ignition sources in the area, and the limited combustible material in the area. Therefore, RAI 19.1.0-4 S0s 1 and 2, Part F is resolved.

Based on the staff's review of the risk achievement results, the shutdown fire PRA results are not as sensitive to operator errors as they are to common cause equipment failures in the following systems: GDCS, ADS, Q-DCIS, the UPS, and the dc power supply system. The CCFs in these systems have the highest RAW values. For example, the Q-DCIS, UPS, and dc power supply system have RAW values exceeding 1,000. In contrast, failure of the operator to recognize the need for low pressure makeup after depressurization has a RAW value of approximately 26. Failure of the operator to open two DPVs manually has a RAW value of approximately 8. Failure of the operator to actuate the FPS in LPCI mode has a RAW value of approximately 7.

19.1.6.2.1.4 Conclusion

The staff reviewed the GEH shutdown fire risk assessment and finds it to be technically adequate to support design certification and the identification of risk insights.

19.1.6.2.2 Results and Insights from the Low-Power and Shutdown Internal Flooding Risk Assessment

19.1.6.2.2.1 Summary of Technical Information

As in the full-power assessment, the applicant performed the shutdown internal flooding analysis using equipment locations based on existing plant layout drawings. Also similar to the full-power assessment, the applicant divided buildings into flood zones based on separation for flooding. GEH screened those flood zones that do not contain flood sources or PRA equipment from consideration.

Depending on the building and the origin of the flood, GEH considered the following aspects for flood propagation: automatic flood detection systems, automatic systems to terminate flooding, watertight doors to prevent the progression of flooding, sump pumps, and other design or construction characteristics that contribute to minimize the consequences of flooding.

The estimated mean shutdown flooding CDF is 5.2×10^{-9} /yr. The estimated LRF is also 5.2×10^{-9} /yr since the containment is assumed to be open. The estimated CDF accounts for the number of hours in each operating mode and the frequency of an outage (once every 2 years).

The following paragraphs describe the top four flooding sequences that contribute approximately 56 percent of the shutdown flooding CDF of 5.2×10^{-9} /yr.

Flooding Sequence 1, contributing about 24 percent, is initiated by a break in the makeup water system in RB elevation 17,500 mm (57.4 ft) (Flood Zone RB3-P30-L-M5, M5O, and M6U).

Flooding Sequence 2, contributing about 16 percent, is initiated by a flood caused by a service water line break in the service water building (Flood Zones SF-P41A_S_SD and SF-P41B_S_SD), which impacts the PSWS.

Flood Sequence 3, contributing about 10 percent, is initiated by a break in the FPS in the TB elevation 4,650 mm (15.3 ft) (Flood Zone TB-U43-L-M5, M5O, and M6U).

Flood Sequence 4, contributing about 6 percent, is initiated by a flood in the TB main condenser (Flood Zone TBC-B21A-S-M5, M5O, and M6U), which impacts the RWCU/SDC system.

19.1.6.2.2.2 Acceptance Criteria

No specific regulatory requirements govern the safety insights used to support design certification. However, the staff used applicable guidance from SRP Section 19.0, Revision 2, in its review.

The staff considered the results and insights for shutdown risk assessment with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report.

19.1.6.2.2.3 Staff Evaluation

GEH used the internal events shutdown PRA to construct the shutdown flooding PRA. The shutdown PRA uses the same system success criteria, and the containment hatches are assumed to be open. The staff considers this to be an acceptable approach. As in the full-power assessment, the applicant estimated the initiating event frequency for each flood zone by summing the frequencies for flood components and piping for the system under consideration. GEH referenced NUREG/CR-6928, "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants," issued February 2007, for the rupture features, and Nuclear Safety Advisory Center (NSAC)-60, "A Probabilistic Risk Assessment of Oconee, Unit 3," issued June 1984, for the expansion joint failure data. The staff considers these to be appropriate data sources.

GEH estimated the shutdown CDF for each flood damage state by quantifying the loss of RWCU/SDC for three POSS: Mode 5, Mode 5 (Open), and Mode 6 (Unflooded). The applicant did not consider Mode 6 (Flooded) since the water above the core will be adequate to provide core cooling for 24 hours. The staff agrees that Mode 6 (flooded) need not be considered because of the abundant cooling capability when the vessel is flooded.

Based on the staff review of the risk achievement results, the shutdown flooding PRA results are not as sensitive to operator errors as they are to common cause equipment failures in the following systems: GDCS, ADS, and Q-DCIS equipment. These CCFs have the highest RAWs, which are greater than 100. In contrast, two operator actions, failure of the operator to actuate the FPS in LPCI mode and failure of the operator to recognize the need for low-pressure makeup after depressurization, have RAW values of approximately 11 and 18, respectively.

19.1.6.2.2.4 Conclusion

The staff has reviewed GEH's shutdown flooding risk assessment and finds it to be technically adequate to support design certification and the identification of risk insights.

19.1.6.2.3 Results and Insights from the Low-Power and Shutdown Internal High-Winds Risk Assessment

19.1.6.2.3.1 Summary of Technical Information

As in the full-power assessment, GEH performed the following major steps to complete the high-winds risk analysis:

- Tornado hazard frequency
- Tornado-induced plant impacts
- Calculation of tornado-induced CDFs and release frequencies

- Hurricane hazard frequency
- Hurricane-induced plant impacts
- Calculation of hurricane-induced CDFs and release frequencies

Similar to the full-power analysis, the applicant calculated the tornado strike initiating event frequency using the methodology provided in NUREG/CR-4461. To ensure a bounding analysis, tornado strike initiating frequencies that encompass most sites are generated using data from the central region of the United States where the tornado intensities and frequencies of occurrence are highest. In addition, the analysis assumed an ESBWR characteristic length of 400 feet, which represents a value double the assumed characteristic length used in NUREG/CR-4461. This results in the doubling of the strike probabilities for finite structures. GEH then estimated the shutdown tornado frequencies by multiplying the strike frequencies by the number of hours per calendar year that the plant is expected to be in each shutdown plant operating state.

GEH assumed that the risk associated with LOPP due to a tornado strike when the reactor well is flooded (Mode 6 [Flooded]) is negligible because of a large quantity of water that is passively available to provide cooling for a time period in excess of 24 hours. This period allows for an adequate path from an external water source to the reactor well to be established. Equipment and systems, such as CRD pumps, FAPCS pumps, RWCU/SDC pumps, and firewater pumps, are housed in seismic Category I structures and would be available to provide an adequate cooling pathway when powered from onsite power. For this reason, the ESBWR high-winds analysis did not consider the shutdown analysis for Mode 6 (Flooded) operations. The staff accepts this approach.

As in the full-power analysis, GEH obtained the LOPP data used to determine the strike frequency associated with hurricane events from NUREG/CR-6890. The applicant collected a subset of the coastal plant data for plants located on shorelines and in areas with high return rates for hurricanes. These data were limited to plants located in Florida, Louisiana, and North Carolina. To calculate a bounding hurricane strike frequency, a total operating duration for shoreline plants is 58.51 reactor critical years (rcy) and 5.49 reactor shutdown-years for a total of 64 rcy. The resulting hurricane initiating event frequency is roughly five times the frequency for all coastal plants. The ESBWR high-winds risk analysis used a hurricane strike frequency of 7.60×10^{-2} events/rcy, which represents an increase by a factor of five over the hurricane initiating frequency for coastal data.

GEH developed hurricane strike frequencies for Mode 5, Mode 5 (Open), and Mode 6 (Unflooded) based on the number of hours per calendar year that the plant is expected to be in each shutdown POS. The analysis assumed one outage every 2 calendar years. The shutdown hurricane Mode 6 (Unflooded) high-winds strike frequency was added to the shutdown hurricane Mode 5 (Open) high-winds strike frequency so that both modes were evaluated assuming Mode 5 (Open) conditions. GEH believes that combining these two modes is acceptable, assuming that coastal plants have several days of warning to prepare for a hurricane strike and should be able to transition to a plant configuration such as Mode 5 (Open) before the hurricane strike.

GEH used the shutdown PRA accident sequence structures, system fault trees, and success criteria to calculate shutdown high-winds CDF and releases. GEH estimated the mean high-winds shutdown CDF to be 4.0×10^{-8} /yr. Since GEH assumed the containment to be open during Modes 5 and 6, this CDF is also the LRF. A hurricane-induced loss of offsite power

during Mode 5 and Mode 5 (Open) accounts for over 99 percent of the shutdown high-winds CDF.

19.1.6.2.3.2 Acceptance Criteria

No specific regulatory requirements govern the safety insights used to support design certification. However, the staff used applicable guidance from SRP Section 19.0, Revision 2, in its review.

The staff considered the results and insights for shutdown risk assessment with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report.

19.1.6.2.3.3 Staff Evaluation

19.1.6.2.3.3.1 Shutdown High-Winds, Risk-Significant Core Damage Scenarios and Dominant Contributors

The staff has reviewed the applicant's explanation of dominant contributors to risk and finds it acceptable. In addition, and for the reasons discussed below, the staff finds that combining the high-winds strike frequencies for Mode 5 (Open) and Mode 6 (Unflooded) is an acceptable approach for treating these conditions.

GEH did not assess the high-winds risk during Mode 6 (Unflooded) operation. In Mode 6 (Unflooded), the containment is open, the reactor vessel is open, and the water above the core will not keep the core cool for an extended period without additional mitigating systems. GEH assumed that there would be sufficient time before a hurricane strike for the plant to transition to another mode so that long-term cooling water would be more reliable. The model reflects this assumption by adding the shutdown hurricane Mode 6 (Unflooded) high-winds strike frequency to that of the shutdown hurricane Mode 5 (Open). GEH documented this assumption in DCD Tier 2, Revision 6, Table 19.2-3, as a key risk insight from the analysis. Table 19.2-3 now contains an entry that states the following:

The plant should not be in a Mode 6 Unflooded condition when a hurricane strike occurs. This is because in Mode 6 Unflooded the containment is open, the reactor vessel is open and the water above the core will not keep the core cool for an extended period of time.

The staff finds this treatment of high-winds risk during Mode 6 (Unflooded) operation to be acceptable since this key risk insight will be available to all COL applicants that reference the ESBWR design certification.

The high-winds risk assessment presented in Revision 4 of the PRA report does not explicitly quantify scenarios that could occur during Mode 4 because of the short period assumed for transition from Mode 3 to Mode 5. The staff recognized that the PRA report, Revision 4, Table 18-1, and DCD Tier 2, Table 19.2-3, did not capture certain implicit insights. In RAI 19.1-186, the staff asked the applicant to address two important implicit assumptions in the high-winds risk assessment: (1) the plant will go to Mode 4 and will not deinert in Mode 4 when the plant shuts down in anticipation of a hurricane strike and (2) when a hurricane is approaching the site, the plant will not voluntarily take any equipment out of service that is credited in the high-winds PRA. In its response, the applicant has added these insights in DCD Tier 2,

Revision 7, Table 19.2-3, and Table 18-1 of the PRA report, Revision 5. This is acceptable to the staff. Therefore, RAI 19.1-186 is resolved.

19.1.6.2.3.3.2 Results and Insights from the Shutdown High-Winds Importance and Sensitivity Studies

The applicant has performed studies of RAW using the high-winds PRA model. The results of these studies show that the shutdown high-winds PRA results are not as sensitive to operator errors as they are to common cause equipment failures in the following systems: GDCS, ADS, Q-DCIS, UPS, and dc power supply system, which have the highest RAWs. For example, CCFs in the Q-DCIS, UPS, and dc power supply system have RAW values exceeding 1,000. In contrast, failure of the operator to recognize the need for low-pressure makeup after depressurization has a RAW value of approximately 30. Failure of the operator to open two DPVs manually has a RAW value of approximately nine.

The staff has reviewed the applicant's sensitivity studies and finds that they are acceptable for gathering important insights regarding the risk contribution from high winds during shutdown operation.

19.1.6.2.3.4 Conclusion

The staff reviewed the GEH shutdown high-winds risk assessment and finds it be technically adequate to support design certification and the identification of risk insights.

19.1.6.2.4 Results and Insights from the Low-Power and Shutdown Internal Seismic Assessment

19.1.6.2.4.1 Summary of Technical Information

Similar to the full-power assessment, GEH performed a shutdown SMA to calculate HCLPF seismic capacities for important accident sequences and accident classes. The PRA-based seismic margins approach used in this analysis evaluates the capability of the plant to withstand an earthquake of 1.67 times the SSE. GEH used the MIN-MAX method to determine the functional and accident sequence fragilities.

19.1.6.2.4.2 Acceptance Criteria

No specific regulatory requirements govern the safety insights used to support design certification. However, the staff used applicable guidance from SRP Section 19.0, Revision 2, in its review.

The staff considered the results and insights for shutdown risk assessment with respect to the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report.

19.1.6.2.4.3 Staff Evaluation

The HCLPF nodal fault trees used for the shutdown seismic analysis are the same as those used in the at-power seismic analysis, with the exception of the structural failure node. The structural integrity for shutdown nodal fault tree, which is used in the shutdown seismic event tree, is developed to include the structural failures included in the at-power structural integrity

nodal fault tree, as well as the structural elements related to reactivity control. This approach is acceptable to the staff.

The accident sequence analysis assumed the earthquake-induced initiating event to be an LOPP. The model assumes that scenarios with structural failures will lead directly to core damage. GEH developed shutdown seismic event trees for Mode 5, Mode 5 (Open), Mode 6 (Unflooded), and Mode 6 (Flooded). No shutdown accident sequence has an HCLPF lower than 0.84g because of the assumption made for component-level HCLPF. The PRA-based shutdown SMA shows that the ESBWR design can meet the 0.84g HCLPF value, if the seismic capacities of safety system components are qualified to be above the specified acceptable design value of 0.84g. In DCD Tier 2, Revision 6, Section 19.2.6, the applicant stated the following:

The COL applicant referencing the ESBWR certified design shall compare the as-built SSC HCLPFs to those assumed in the ESBWR SMA shown in Table 19.2-4 [of the DCD Tier 2, Revision 6]. Deviations from the HCLPF values or other assumptions in the seismic margins evaluation shall be analyzed to determine if any new vulnerabilities have been introduced.

The staff finds this COL information item (i.e., COL Information Item 19.2.6-1-A) to be acceptable.

19.1.6.2.4.4 Conclusion

The staff has reviewed GEH's shutdown seismic assessment and finds it technically adequate to support design certification and the identification of risk insights.

19.1.7 Probabilistic Risk Assessment-Related Input to Other Programs and Processes

19.1.7.1 Summary of Technical Information

The applicant used the PRA insights and assumptions to develop a list of design certification requirements. DCD Tier 2, Revision 9, Table 19.2-3, incorporates these requirements, as appropriate, to ensure that any future plant that references the ESBWR design will be built and operated in a manner consistent with the important assumptions made in the ESBWR design certification PRA.

19.1.7.2 Acceptance Criteria

No specific regulatory requirements govern the safety insights used to support design certification. However, the staff used applicable guidance from SRP Section 19.0, Revision 2, in its review.

The staff evaluated the PRA input to the design certification process against the Commission's objectives for new reactor designs, as stated in Section 19.1.1 of this report. The following three objectives are especially relevant:

- (1) Develop an in-depth understanding of design robustness and tolerance of severe accidents initiated by either internal or external events.

- (2) Develop a good appreciation of the risk significance of human errors associated with the design and characterize the key errors in preparation for better training and more refined procedures.
- (3) Identify important safety insights related to design features and assumptions made in the PRA to support certification requirements, such as ITAAC, design reliability assurance program (D-RAP) requirements, and TS, as well as COL and interface requirements.

19.1.7.3 Staff Evaluation

19.1.7.3.1 Probabilistic Risk Assessment Input to the Design Certification Process

The applicant achieved the first two objectives by identifying the dominant accident sequences, as well as the risk-important design features and human actions (see Sections 19.1.3 through 19.2.6 of this report).

The staff reviewed the list of design certification requirements and determined that it did not reflect all of the important assumptions made in the PRA. The staff issued RAI 19.1.0-4 S01, in order to understand why certain assumptions and insights were not translated into design certification requirements. The staff tracked RAI 19.1.0-4 S01, Parts A through F as open items in the SER with open items. In response, the applicant reviewed the assumptions in the PRA and, using its process for identifying and documenting key assumptions and risk insights, GEH included additional assumptions related to design and operation in DCD Tier 2, Revision 6, Table 19.2-3. The applicant also provided additional explanation of its process for ensuring that key assumptions and risk insights are identified and documented for use by COL applicants. The staff has reviewed the revisions in DCD Tier 2, Revision 6, and finds them acceptable. Therefore, RAI 19.1.0-4 S01 is resolved.

In light of the revisions made to Table 19.2-3 in DCD Tier 2, Revision 6, the staff finds that the applicant has achieved the Commission's objective of identifying important safety insights related to design features and assumptions made in the PRA to support certification requirements.

19.1.7.3.2 Probabilistic Risk Assessment Input to the Maintenance Rule Implementation

Importance measures are derived from the PRA and used to develop a list of risk-significant SSCs for the ESBWR design certification, as discussed in DCD Tier 2, Revision 9, Section 17.4.6. Section 17.4 of this report documents the staff's evaluation of the information provided in DCD Tier 2, Revision 9, Section 17.4.6.

19.1.7.3.3 Probabilistic Risk Assessment Input to the Reliability Assurance Program

The ESBWR D-RAP is a program utilized during detailed design and specific equipment selection phases to ensure that the important ESBWR reliability assumptions of the PRA are considered throughout the plant life. The PRA is used to evaluate the plant response to anticipated operational occurrence initiating events and mitigation to ensure that potential plant damage scenarios pose a very low risk to the public. The D-RAP identifies relevant aspects of plant operation, maintenance, and performance monitoring of important plant SSCs for owner/operator consideration in ensuring equipment safety and limiting risk to the public. GEH used the importance measures derived from the PRA to develop a list of risk-significant SSCs for the ESBWR design certification, as discussed in DCD Tier 2, Revision 9, Section 17.4.6.

Section 17.4 of this report documents the staff's evaluation of the D-RAP and the applicant's use of the PRA to support the program.

19.1.7.3.4 Probabilistic Risk Assessment Input to the Regulatory Treatment of Non-Safety-Related Systems Program

The ESBWR design process uses a systematic approach to identify regulatory guidance and assess it relative to specified ESBWR design features to determine whether additional regulatory treatment is warranted for SSCs that perform a significant safety, special event, or postaccident recovery function. The ESBWR design process includes the use of both probabilistic and deterministic criteria to achieve the objectives of SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," dated March 28, 1994. The RTNSS process requires an assessment of safety functions that are relied upon during at-power and shutdown conditions to meet the NRC's safety goal guidelines. A comprehensive assessment to identify RTNSS candidates includes focused PRA sensitivity studies for internal events, evaluations of external events, an assessment of the effects of nonsafety-related systems on initiating event frequencies, and an assessment of uncertainties in these analyses and uncertainties that may be introduced by first-of-a-kind passive components. Section 22 of this report documents the staff's evaluation of the focused PRA studies used to support the RTNSS process.

19.1.8 Conclusion

The staff evaluated the ESBWR PRA and its use in the design and certification processes and identified a number of issues that the applicant did not adequately address. GEH has now addressed all of these issues adequately through its responses to the staff's RAIs. The staff has described each open issue and the basis for resolution of the issue in the appropriate section of this report. Based on its review, the staff finds that the applicant has adequately addressed the Commission's objectives, which are described in Section 19.1.1, regarding the preparation and use of a PRA in the design and certification processes.

19.2 Severe Accident Evaluations

19.2.1 Regulatory Criteria

The staff reviewed the applicant's description and analysis of the design features to prevent and mitigate severe accidents, in accordance with the requirements in 10 CFR 52.47(a)(23). This review covered specific issues identified in SECY-90-016 and SECY-93-087, which the Commission approved in related SRMs dated June 26, 1990, and July 21, 1993, respectively, for prevention (e.g., ATWS, midloop operation, SBO, fire protection, and ISLOCA) and mitigation (e.g., hydrogen generation and control, core debris coolability, high-pressure core melt ejection, containment performance, dedicated containment vent penetration, and equipment survivability).

In addition, the staff reviewed the information the applicant provided to satisfy the requirements 10 CFR 52.47(a)(8).

The staff used applicable guidance from SRP Section 19.0, Revision 2 in its review.

19.2.2 Severe Accident Prevention

19.2.2.1 Severe Accident Prevention Features

Section 19.1.3.1 of this report summarizes important severe accident prevention features.

19.2.2.1.1 Anticipated Transients without Scram

For ATWS prevention and mitigation, the ESBWR is designed with the following features:

- An ARI system that utilizes sensors and logic that are diverse and independent of the RPS
- Electrical insertion of FMCRDs that also utilize sensors and logic that are diverse and independent of the RPS
- Automatic feedwater runback under conditions indicative of an ATWS
- Automatic initiation of SLCS under conditions indicative of an ATWS
- Elimination of the scram discharge volume in the CRD system

DCD Tier 2, Revision 9, Section 15.5.4, discusses the effectiveness of these design features for addressing ATWS concerns. Given these features, the ESBWR PRA demonstrates that ATWS provides an insignificant contribution to CDF and LRF.

19.2.2.1.2 Midloop Operations

Not applicable

19.2.2.1.3 Station Blackout

During a total loss of offsite power, the safety-related electrical distribution system is automatically powered from the onsite nonsafety-related diesel generators. If these diesel generators are not available, then each division of the safety-related system independently isolates itself from the nonsafety-related system, and the safety-related batteries of each division provide uninterrupted power to safety-related loads of each safety-related load division. The divisional batteries are sized to provide power to required loads for 72 hours. DCD Tier 2, Revision 9, Section 15.5.5, documents conformance to the requirements of 10 CFR 50.63. Because of the nature of the passive safety-related systems in the ESBWR, SBO events are not significant contributors to CDF or LRF.

19.2.2.1.4 Fire Protection

The FPS does not perform any safety-related function. The FPS serves as a preventive feature for severe accidents in two ways: (1) by reducing or eliminating the possibility of fire events that could induce transients, damage mitigation equipment, and hamper operator responses, and (2) as a means for long-term makeup to the upper containment pools, which may be required after the first 72 hours of an accident requiring passive heat removal.

The FPS connects to the safety-related portion of the FAPCS. The FPS has RTNSS functions that provide post-72-hour makeup to the IC/PCCS pools and SFP using this portion of the

FAPCS. The FPS primary water storage tank also has the RTNSS function of providing makeup water for reactor coolant inventory.

Section 19.1.5.2 of this report summarizes the risk significance of fire. Performance of RTNSS functions, and the piping supporting these functions, is assured by applying the augmented design standards (Category B) described in DCD Tier 2, Revision 9, Section 19A.8.3.

19.2.2.1.5 Intersystem Loss-of-Coolant Accident

As stated earlier in Section 19.1.3.1 of this report, the design of the ESBWR reduces the possibility of ISLOCA outside containment by designing all piping systems, major system components, and subsystems connected to the RCPB to have ultimate rupture strength at least equal to the RCPB pressure. Given these design features, ISLOCA is not a significant contributor to initiating events or accidents.

19.2.2.1.6 Alternating Current-Independent Fire Water Addition System

The FPS not only plays an important role in preventing core damage, but it is also the backup source of water for flooding the LDW should the core become damaged and relocate into the containment (the primary source is the deluge subsystem pipes of the GDSCS). The primary injection path is through the feedwater line and into the RPV. This system must be manually aligned. This is appropriate because the sequences in which it is useful are slow to develop and easy to identify.

19.2.2.1.7 Vessel Depressurization

Section 19.1.3.1 of this report describes this issue.

19.2.2.1.8 Isolation Condenser

Section 19.1.3.1 of this report describes this issue.

19.2.2.2 Conclusion

The applicant has provided a number of important design features that contribute to the prevention of severe accidents. The staff has evaluated the impact of these features on risk and finds that in many cases these features can substantially reduce the risk associated with severe accidents. The staff concludes that, in accordance with the Commission's objectives for new reactor designs, the applicant has reduced the significant risk contributors of existing operating plants by introducing appropriate and effective design features that contribute to the prevention of severe accidents.

19.2.3 Severe Accident Mitigation

19.2.3.1 Overview of Containment Design

Figure 19.2-1 illustrates the ESBWR containment design features that would mitigate severe accidents, and Sections 19.1.3.1.2 and 19.1.3.1.3 discuss the major features.

19.2.3.2 Severe Accident Progression

Severe accident progression can be divided into two phases: an in-vessel phase and an ex-vessel phase. The in-vessel phase generally begins with insufficient DHR and can lead to melt-through of the reactor vessel. The ex-vessel phase involves the release of the core debris from the reactor vessel into the containment and resulting phenomena, such as CCI, FCI, and DCH.

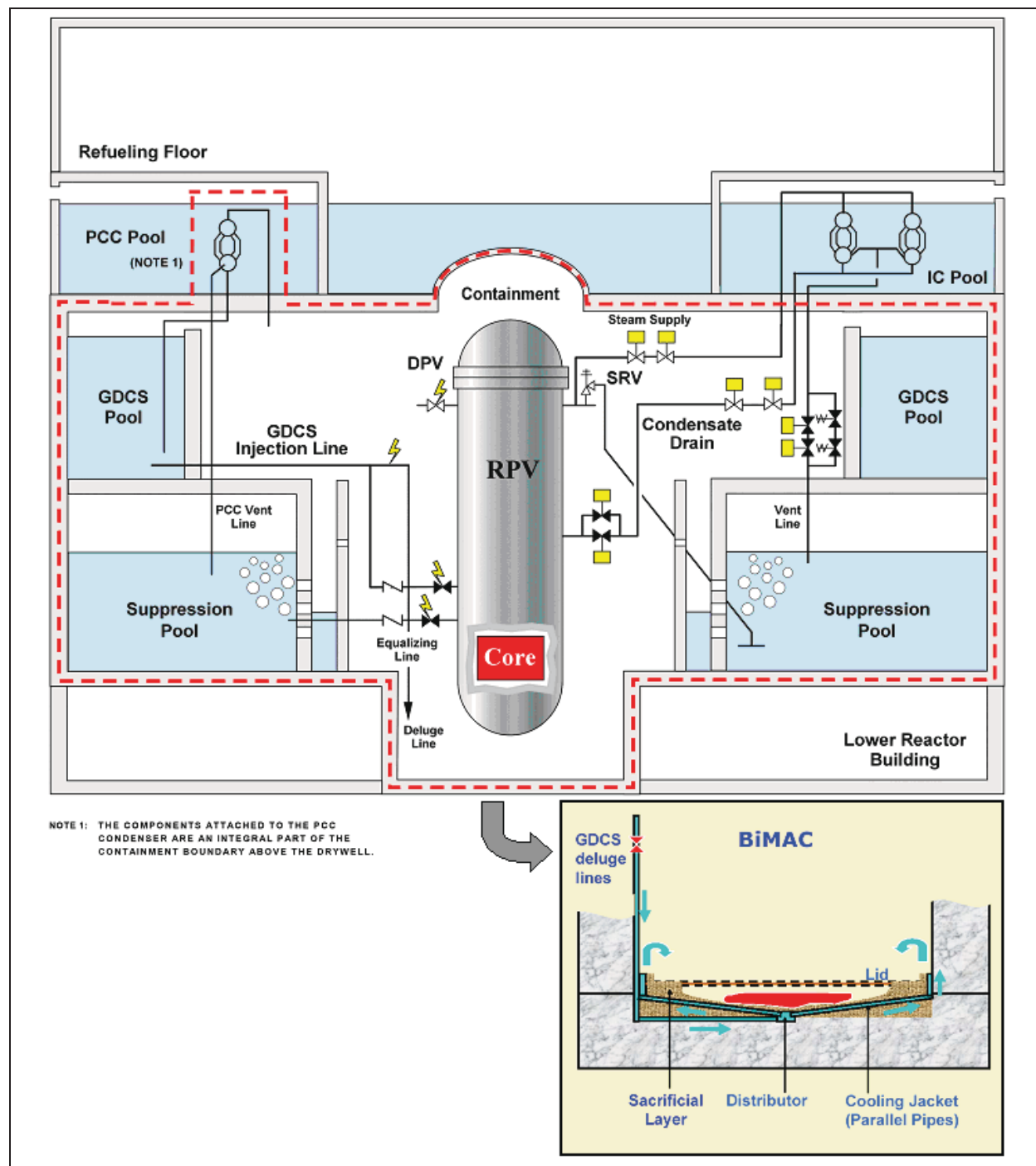


Figure 19.2-1. ESBWR design features for severe accident conditions.

19.2.3.2.1 In-Vessel Melt Progression

In-vessel melt progression establishes the initial conditions for assessing the thermal and mechanical loads that may ultimately threaten the integrity of the containment. In-vessel melt progression begins with uncovering of the core and initial heatup and continues until either (1) the degraded core is stabilized and cooled within the reactor vessel or (2) the reactor vessel is breached and molten core material is released into the containment. The phenomena and processes in the ESBWR that can occur during in-vessel melt progression include the following:

- Core heatup resulting from loss of adequate cooling
- Exothermic metal-water reactions that oxidize cladding and produce hydrogen
- Eutectic interactions (i.e., mixtures of materials with a melting point lower than that of any other combination of the same components) between core materials (e.g., control blades and fuel assembly channel boxes, resulting in relocation of molten material)
- Melting and relocation of cladding, structural materials, and fuel
- Formation of blockages near the bottom of the core resulting from the solidification of relocating molten materials
- Drainage of molten materials to the vessel lower head region
- Formation of a melt pool, natural circulation heat transfer, crust formation, and crust failure in the lower head region
- Lower head breach resulting from failure of a penetration or from local or global creep-rupture

As the temperature of the core increases, fission products in vapor form are released. As the vapors rise, they condense into liquid aerosols, which can either be deposited on surfaces, such as upper internal structures, or flow along with the steam and hydrogen out of the RPV, either through the SRV lines to the suppression pool during RCS depressurization or through breaks in the RCS boundary.

The core melt progression, including relocation and fission product release, becomes increasingly difficult to predict as the core continues to degrade. The core melt could relocate into the lower reactor vessel plenum. If water is present in the lower plenum, the potential exists for in-vessel steam explosions, where molten fuel rapidly fragments and transfers its energy, causing rapid steam generation and shock waves. Another possibility is that the core debris within the lower plenum may melt through the reactor vessel or interact with available water before melting through and entering the LDW.

19.2.3.2.2 Ex-Vessel Melt Progression

Ex-vessel severe accident progression is affected by the mode and timing of the reactor vessel failure; the primary system pressure at reactor vessel failure; the composition, amount, and character of the molten core debris expelled; the type of concrete used in containment construction; and the availability of water to the LDW. The initial response of the containment to ex-vessel severe accident progression is largely a function of the pressure of the RCS at reactor

vessel failure and the existence of water within the reactor cavity. If not prevented through design features, risk consequences are usually dominated by early CF mechanisms that could result from energetic severe accident phenomena, such as HPME with DCH and EVEs. The long-term response of the containment from ex-vessel severe accident progression is largely a function of the containment pressure and temperature resulting from CCI and the availability of CHR mechanisms.

At high RCS pressures, the molten core debris could be ejected from the reactor vessel in jet form causing it to fragment into small particles. The potential exists for the core debris ejected from the vessel to be swept out of the LDW and into the UDW. Finely fragmented and dispersed core debris could heat the containment atmosphere and lead to large pressure spikes. In addition, chemical reactions of the core debris particulate with oxygen and steam could add to the pressurization loads. This severe accident phenomenon is known as HPME with DCH.

To prevent this phenomenon, the ESBWR has incorporated an ADS to ensure that, in the event of a core melt scenario, failure of the RPV would occur at a low pressure. Should the RPV fail at a high pressure, the design of the ESBWR containment would provide an indirect pathway from the LDW to the UDW in an effort to decrease the amount of core debris that could contribute to DCH.

RPV failure at high or low pressure coincident with water present within the LDW could lead to FCI with the potential for rapid steam generation or steam explosions. Rapid steam generation involves the pressurization of containment compartments from nonexplosive steam generation beyond the capability of the compartment to relieve the pressure so that local overpressurization failure of the compartment occurs. Steam explosions involve the rapid mixing of finely fragmented core debris with surrounding water, resulting in rapid vaporization and acceleration of the surrounding water creating substantial pressure and impact loads. The ESBWR is designed so that there is a very low likelihood of water within the LDW at the time of reactor vessel failure.

The ESBWR has incorporated a passive debris cooling device, the BiMAC, to cool debris once it enters the LDW. Without such a device, contact of molten core debris with concrete in the LDW would lead to CCI. CCI involves the decomposition of concrete from core debris and can challenge the containment through various mechanisms, including: (1) pressurization resulting from the production of steam and noncondensable gases to the point of containment rupture, (2) transport of high-temperature gases and aerosols into the UDW leading to high-temperature failure of the containment seals and penetrations, (3) liner melt-through, (4) reactor pedestal melt-through leading to relocation of the reactor vessel and tearing of containment penetrations, and (5) production of combustible gases such as hydrogen and carbon monoxide. CCI is affected by many factors, including the availability of water to the LDW, the containment geometry, the composition and amount of core melt, the core melt superheat, and the type of concrete involved.

19.2.3.3 Severe Accident Mitigative Features

The ESBWR containment has been designed with specific mitigating capabilities. These capabilities not only mitigate the consequences of a severe accident, but also address uncertainties in severe accident phenomena. Section 19.1.3 of this report describes these features and discusses the specific severe accident phenomena addressed by the mitigation system.

The following discussion evaluates how the ESBWR design addresses the severe accident mitigative features issues, including those raised in SECY-90-016 and SECY-93-087.

19.2.3.3.1 Hydrogen Generation and Control

19.2.3.3.1.1 Staff Evaluation

The analysis of the radiolytic oxygen concentration in containment, as discussed in Section 8.1 of the PRA report, Revision 6, is based on the methodology of Appendix A to SRP Section 6.2.5, Revision 2 and RG 1.7, "Control of Combustible Gas Concentrations in Containment."

The analysis results show that the time required for the oxygen concentration in the drywell or suppression chamber (wetwell airspace) to increase to the deinerting value of 5 percent is significantly greater than 24 hours for a wide range of fuel cladding-steam interaction and iodine release assumptions of up to 100 percent of the initial core inventory.

Therefore, the Level 2 PRA does not take credit for venting to prevent unacceptable hydrogen and oxygen concentrations in the drywell or the suppression chamber. Venting for pressure relief is modeled as an operator action (i.e., no mechanical faults).

There are two locations, the PCCS and the ICS, where local combustible conditions could be reached. These are discussed separately below.

19.2.3.3.1.1.1 Preventive and Mitigative Features

In the ESBWR, the containment inerting system is provided to establish and maintain an inert atmosphere within the containment. This inerting prevents the combustion of hydrogen. The containment is inerted during operation, except for short periods immediately before and after scheduled shutdowns when the containment is deinerted to establish a clean, breathable atmosphere throughout the containment while the containment is still closed.

19.2.3.3.1.1.2 Risk Caused by Deinerted Operation

The PRA analysis assumes a 24-hour/yr period of noninerted containment atmosphere. This adds an additional BYP frequency of 4.5×10^{-11} /yr.

19.2.3.3.1.1.3 Risk Caused by Hydrogen and Oxygen in the PCCS

During a LOCA, hydrogen and oxygen are generated as a result of radiolysis of water inside the pressure suppression pool and eventually enter the drywell. These gases appear in the containment at very dilute concentrations. The drywell atmosphere mixture of steam and noncondensable gases, (i.e., nitrogen, oxygen and the radiolytic gases) flow into the PCCS upper drums. The steam component condensed in the PCCS tube array collects in the lower PCCS drums and drains back into the drywell by gravity. The leftover noncondensable gases (i.e., hydrogen, oxygen, nitrogen) exit the PCCS through vent lines from the lower drums to the wetwell. Over time the majority of the nitrogen in the drywell is eventually forced into the wetwell by this process and the remaining noncondensable gases in the drywell are hydrogen and oxygen continuously produced by radiolysis. GEH analyses in NEDO-33572, Revision 3, "ESBWR ICS and PCCS Condenser Combustible Gas Mitigation and Structural Evaluation,"

show that with time these gases accumulate in the lower portions of the PCCS tubes and the lower drums, resulting in combustible concentrations.

GEH added that PCCS components have been evaluated to determine the effects of detonation in a tube and in the lower drum for a range of mixture concentrations. A bounding detonation pressure for a pure stoichiometric mixture of hydrogen and oxygen is calculated using the highest peak pressures during a LOCA. It is then applied statically for the PCCS condenser using dynamic load factors in a finite element model. The calculated stresses for the detonation load are combined with those from seismic and LOCA thermal loads. The acceptance criteria for components subject to detonation is based on the ability of those components to retain their pressure integrity without undergoing plastic deformation. The thickness of downstream piping and components is sized to accommodate the resulting detonation loads.

Additionally, the magnitude of the detonation loads on the downstream components is minimized by igniters in each lower drum, and safety-related catalyst modules at the entrance of each vent pipe in the condenser lower drum. The igniters prevent excessive oxygen from accumulating to a combustible mixture during severe accident conditions. The catalyst modules keep hydrogen concentrations in the PCCS vent below levels at which detonation events can occur.

19.2.3.3.1.1.4 Risk Caused by Hydrogen and Oxygen in the ICS

During plant transients in which the RPV is isolated, the ICS removes heat, while the condenser vent lines keep the units continuously purged of noncondensable gases. The ICS vent line valves automatically open on a time delay after the ICS is initiated, regardless of system pressure.

During a LOCA, the ICS initiates in order to supply the additional condensate stored in its drain piping to the RPV. If the condensers are not isolated, there is potential for condensation to occur, and given enough time, this could allow combustible gas concentrations to accumulate in the ICS condenser following a LOCA. This would be similar to the process discussed in the previous section for the PCCS.

To prevent combustible gas buildup from occurring, the ICS containment isolation valves automatically close after receiving an indication that the depressurization valves on the RPV have opened. This will prevent flow through the ICS and hence averts the buildup of detonable mixtures.

19.2.3.3.1.1.5 Basis for Acceptability

The specific requirements in 10 CFR 50.44(c)(2) establish the following for future water-cooled reactor applicants and licensees:

[a]ll containments must have an inerted atmosphere, or must limit hydrogen concentrations in containment during and following an accident that releases an equivalent amount of hydrogen as would be generated from a 100 percent fuel clad-coolant reaction, uniformly distributed, to less than 10 percent (by volume) and maintain containment structural integrity and appropriate accident mitigating features.

The design of the ESBWR provides for inerted containment and, as a result, requires no system to limit hydrogen concentration.

The ESBWR containment, in accordance with 10 CFR 50.34(f)(2)(ix), can withstand the pressure and energy addition during and following an accident that releases an amount of hydrogen equivalent to that generated from a 100-percent fuel clad-coolant reaction, uniformly distributed, to less than 10 percent (by volume) and maintain containment structural integrity and appropriate accident mitigating features.

In SECY-00-0198, "Status Report on Study of Risk-Informed Changes to the Technical Requirements of 10 CFR Part 50 (Option 3) and Recommendations on Risk-Informed Changes to 10 CFR 50.44 (Combustible Gas Control)," dated September 14, 2000, the staff recommended changes to 10 CFR 50.44 to reflect the position that only combustible gas generated by a beyond-DBA is a risk-significant threat to containment integrity.

During severe accident conditions with a significant amount of fission product gases and hydrogen release to the containment, the containment will remain inerted without any additional action because radiolytic oxygen production remains below the concentration that could pose a risk of hydrogen burning for a significant period of time following the event. Implementation of the severe accident management guidelines (SAMGs) will manage the accumulation of combustible gases that may develop in the period after about 24 hours. For a severe accident with a substantial release of hydrogen, the oxygen concentration in containment from radiolysis is not expected to reach 5 percent for significantly longer than 24 hours.

The design and mitigation features covered in this section are sufficient to support the statement that the PCCS components are designed to maintain their integrity for design basis accidents as well as severe accidents, including consideration of local combustible gas accumulations under LOCA conditions. The ICS is protected from local combustible gas buildups by the automatic closure of the ICS vents upon operation of the RPV depressurization valves.

According to 10 CFR 50.44(c)(2), which provides the combustible gas control requirements for future water-cooled reactor applicants and licensees, containments with an inerted atmosphere do not require a method to control the potential buildup of postaccident hydrogen.

The ESBWR PRA for severe accidents considers gas generation effects, combustible and noncombustible commingled, for situations in which they can possibly lead to overpressure by their molar additions to the containment atmosphere. The calculated frequency of such failures is acceptably small, as noted in Section 19.1.4.2 of this report.

19.2.3.3.2 Conclusion

The present review confirms that, for ESBWR operations at power with the containment inerted, combustion of hydrogen and other combustible gases does not have to be considered as a safety risk. The ESBWR design is in compliance with the Commission's safety goals and regulations regarding hydrogen combustion and control.

19.2.3.3.3 Core Debris Coolability

19.2.3.3.3.1 Staff Evaluation

In severe accidents that proceed to vessel failure and release molten core material into the containment, the in-vessel melt progression establishes the initial conditions for assessment of the thermal and mechanical loads that may ultimately challenge the integrity of the containment. The end stages of the in-vessel process are the formation of a melt pool in the vessel lower head region, subsequent lower head breach resulting from failure of a penetration or from local or global creep-rupture, and relocation of the molten material into the LDW region. The initial response of the containment to ex-vessel severe accident progression is largely a function of the pressure of the RCS at reactor vessel failure and the existence of water within the reactor cavity.

For all currently operating LWRs, the severe accident management approach is based on the premise that, provided a sufficient floor area available for spreading and a sufficient amount of water to cover the molten core debris, the debris will become quenched and will remain coolable thereafter. While the ESBWR satisfies the basic conditions for this approach (i.e., the core melt spreadable floor area according to the EPRI URD guidelines for advanced reactors), the core-on-the-floor approach is further improved. GEH has incorporated design features (e.g., the BiMAC device) that, according to the applicant, make the issue of corium-concrete interactions, along with the great uncertainties associated with these interactions, inconsequential.

As one potential option for arresting the melt propagation process and ensuring long-term coolability within the containment boundary, the applicant examined the applicability and effectiveness of in-vessel retention already developed and used for the passive PWR designs in the United States. GEH concluded that this could be a highly effective approach for the ESBWR as well. However, this approach would require all equipment found hanging from the lower head penetrations to be supported from the outside so as to maintain the melt-containing capacity of the lower head. This proved unworkable from an operational perspective, so the option was rejected.

The ESBWR design uses a passively cooled boundary that is designed to be impenetrable by the core debris on the LDW floor. This device is called the BiMAC. The boundary is made by a series of inclined pipes, placed side by side, forming a jacket that can be effectively and passively cooled by natural circulation when subjected to thermal loading on any portion of it. Water is supplied to this device from the GDSCS pools via a set of squib-valve-activated deluge lines. The timing and flows are such that (1) cooling becomes available immediately upon actuation, and (2) the chance of flooding the LDW prematurely, to the extent that such an event results in a vulnerability to steam explosions, is very remote. The jacket is buried inside the concrete basemat and would be called into action only if some or all of the core debris on top is noncoolable.

The paragraphs below describe important considerations in the implementation of this concept.

Pipe inclination angle. Both the thermal load caused by melt natural circulation and the burnout CHF increase with an angle of inclination θ of the bottom boundary from the very low values pertinent for a perfectly horizontal orientation. This increase is much faster for the CHF in the region $0 < \theta < 20$ degrees, and there is a maximum separation around the upper end of this range. Within a reasonable value of the overall vertical dimension of the BiMAC device, the whole LDW can be covered conveniently with pipes inclined near the upper end of this range.

Protective concrete layer. A protective layer of concrete is laid on top of the BiMAC pipes to protect against melt impingement during the initial (main) relocation event and to allow some adequately short time for diagnosing that conditions are appropriate for flooding. This approach will minimize the chance of inadvertent early flooding.

Melt jet impingement. Heat transfer and related phase change processes during melt jet impingement on a solid slab have been studied in the past and their mechanisms are well understood. Notably, because of the high melting point of the jet's liquid, compared to the protective concrete slab's initial temperature, a crust is formed and serves as a thermal boundary condition through which the heat transfer occurs. As stated above, BiMAC is protected by a protective concrete layer to eliminate any challenges resulting from impingement of the superheated, metallic melt jets on the BiMAC cooling pipes.

The BiMAC cavity. The coolable volume, up to the height of the vertical segments of the BiMAC pipes, is approximately 400 percent of the full-core debris. Thus, no possibility exists for the melt to contact the LDW liner; melt can go only into the BiMAC. There is complete floor coverage.

Sump protection. GEH stated that the two sumps needed for detecting leakage flow during normal operation are positioned and protected, as is the rest of the LDW liner, from melt attack. Two sumps are shaped and positioned next to the pedestal wall so that they offer no significant "target" to the melt stream exiting the vessel under most release scenarios.

The LDW deluge system. This system consists of four main lines that feed off the three independent GDCS pools, each separating into three lines. After receiving signals from numerous thermocouples/conductivity probes that cover the LDW floor area and air space indicating melt arrival following RPV breach, the valves on lines that feed into the BiMAC are opened. In the event of a vessel breach away from the very bottom of the lower head, the quantity of melt, the driving force (low-pressure scenario), and the chance of direct impact would be small and thus insufficient to damage the deluge pipes. The valves on lines that feed directly into the LDW will be designed to operate on a diverse detection and activation system. These lines are sized so that any three of them would be sufficient to ensure proper BiMAC functioning (i.e., operation in the natural circulation mode within 5 minutes from melt arrival on the floor). The required reliability of the system (at a high confidence level) is that its failure on demand is not to exceed 1×10^{-3} .

Successful functioning of the BiMAC device depends on the condition that heat removal capability by boiling exceeds the thermal loading resulting from melt natural convection. In addition, it must be shown, through test or analyses, that at the end of the main melt relocation event and associated ablation process, the BiMAC sacrificial layer is left with some material still protecting the steel pipes.

The BiMAC concept is based on sound analytical considerations built on top of separate-effects experiences on burnout heat fluxes in inverted geometries and two-phase (boiling) pressure drop in inclined pipes. Nevertheless, the limits of coolability are defined by the burnout heat flux, or CHF, of water boiling on the inside of the inclined BiMAC pipes. The CHF increases rapidly with angle of inclination, and this increase is most rapid in the interval between 0 and 20 degrees.

The applicant carried out a testing program to demonstrate that the BiMAC device would effectively remove the decay heat in the core debris and thus confirm the design. The staff

requested documentation of the test results in RAIs 19.2-23 S02, and 19.2-25 S02. The staff tracked RAI 19.2-23 S02 and 19.2-25 S02 as open items in the SER with open items. The applicant provided the test results as a topical report (NEDO-33392, Revision 0, "The MAC Experiments Fine Tuning of the BiMAC Design," dated March 28, 2008) in its response to RAIs 19.2-23 S02, and 19.2-25 S02. Review of the report engendered additional RAI questions 19.2-93 through 19.2-119 and supplemental RAIs. GEH responded to these RAIs and GEH also decided to modify the design to change the material on the LDW floor from zirconia to a layer of sacrificial concrete. In response to RAI 19.2-127, GEH submitted an analysis of the effects of erosion of this concrete. The GEH responses satisfactorily show that the BiMAC would be adequately protected and would function as designed. RAIs 19.2-93 through 19.2-119 and RAI 19.2-127 are resolved. Therefore, RAIs 19.2-23 and 19.2-25, including their supplements and the associated open items, are also resolved.

19.2.3.3.3.2 Conclusion

The PRA report, Revision 6, describes the detailed probabilistic framework, quantification of BMP loads, quantification of fragility to BMP, and prediction of failure probability caused by BMP. The results of the BMP device analysis described in the PRA report, Revision 6, show that the BiMAC device would be effective in containing all core melts in a manner that ensures long-term coolability and stabilization of the resulting debris. In this way, the concrete BMP issue becomes moot, as is containment overpressurization generated by the concrete decomposition gases.

19.2.3.3.4 High-Pressure Melt Ejection

19.2.3.3.4.1 Staff Evaluation

At high RCS pressures at the time of RPV failure, a potential exists for the core debris ejected from the vessel to be swept out of the LDW and into the UDW. Finely fragmented and dispersed core debris could heat the containment atmosphere and lead to large pressure spikes. In addition, chemical reactions of the core debris particulate with oxygen and steam could add to the pressurization loads. This severe accident phenomenon is known as HPME with DCH.

In the ESBWR, the UDW is vented to another volume, the wetwell, which contains a large and effective heat sink. As the ESBWR is inerted, any combustion of hydrogen and resulting pressurization loadings is limited to the amount of residual oxygen present within the containment atmosphere.

No specific ESBWR containment design features address the DCH loads other than the general arrangement of the drywell, wetwell, and connecting vent paths.

The set of potential accidents that lead to DCH consists of those involving core degradation and vessel failure at high primary system pressure (the Class III scenarios). The probability of the necessary preceding combinations of events is assessed through the ROAAM process as remote and speculative; that is, the events could, without further analysis, be left in the category of residual risks. Still, because of the potentially severe consequences, the applicant chose to further examine the likelihood of energetic CF from DCH and concluded, by analysis, that such a failure is physically unreasonable.

The key factor in reaching this conclusion is that the approximately 14 square meters (m^2) (150.7 square feet [ft^2]) of vent area, connecting to the condensation potential of the suppression pool, make it virtually impossible to overpressurize the drywell volume. Just as in a LOCA, the timing of vent clearing is important.

The applicant also examined the potential for liner failure resulting from the associated high temperatures in the drywell. For the UDW liner, this type of failure was also found to be physically unreasonable, while for the LDW, because of the immediate proximity and contact with large quantities of melt (given an HPME), local failures, although highly unlikely, cannot be excluded. The consequences of such a possibility are limited by a standard design feature (anchoring), which compartmentalizes the liner and isolates the gap space of the LDW from that of the UDW, clearly eliminating any flowpaths to the outside.

The applicant adapted an existing analytical model to establish the transient containment conditions. The model equations are simple mass and energy balances over the communicating LDW, UDW, and wetwell volumes. This model is verified by comparison with final pressures/temperatures calculated for the original closed system configuration of the original model, as well as sample test results.

Ablation of the initial penetration opening (and of the as yet to be determined protective layer of concrete on top of the BiMAC during HPME) is estimated according to established models and procedures. The results for vessel hole ablation are very similar to those obtained previously, yielding final diameters of 0.2 m and 0.3 m (8 and 12 in.) for 100 and 300 metric-tons (220,500 and 661,400 pounds) of melt involved in the expulsion process, respectively. These results establish the rates of the driving steam escape from the vessel. The containment-limiting fragility is failure of the drywell head.

The margin to failure is the difference between the bounding estimates of loads (upper bound) and fragility (lower bound). The results show that overpressure (catastrophic) failure of the ESBWR containment from DCH is physically unreasonable in terms used in the ROAAM process. This conclusion covers all Class III accidents.

During normal operation, the UDW head is immersed in a water pool, and it remains cold throughout the high-pressure meltdown sequence. Bounding estimates of this process yield internal DW head temperatures of less than 450 K (350.3 degrees F). Thermally-induced failure of the UDW head and/or its seals is thus also physically unreasonable for all Class III accidents.

Thermally-induced failure of the liner, including the penetration areas, is relevant to Class III accidents in which drywell spray is assumed to be unavailable, and these sequences amount to approximately 1 percent of the CDF. As a result of these analyses, GEH found that, even in these cases, strains caused by thermal stress are rather modest (less than 8 percent) in relation to what might be considered necessary for cracking or tearing, even at temperatures approaching the melting point of the material. Bounding calculations of DCH-induced UDW temperatures indicate that the relevant temperature levels are approximately 1,000 K (1,300 degrees F), which is considerably below the near-melting temperatures (over 1,650 K [2510.3 degrees F]) that could cause failure.

However, the GEH calculations also show short periods of potentially very high temperatures in the LDW atmosphere (up to 4,000 K [6,740 degrees F]). These temperatures, and the presence of potentially large quantities of melt in the LDW, indicate that the LDW liner could be subject to

local failures, a condition noted in the high-pressure CET. The branch is used only in a Level 3 sensitivity study.

19.2.3.3.4.2 Conclusion

Based on its review of the applicant's analyses, the staff accepts that the exclusion of DCH-induced catastrophic containment failure is reasonable. Furthermore, based on its confirmatory assessment, the staff also agrees that a high probability of localized liner failures in the LDW exists.

19.2.3.3.5 Fuel Coolant Interactions

The containment function may be challenged by a rapid energy release during an FCI that results in a steam explosion. The term "steam explosion" refers to a phenomenon in which molten fuel rapidly fragments and transfers its energy to the coolant, resulting in rapid steam generation, shock waves, and possible mechanical damage. To be a significant safety concern, the interaction must be very rapid and must involve a large fraction of the core mass. Steam explosions may occur either in the vessel or outside the vessel.

19.2.3.3.5.1 Staff Evaluation

19.2.3.3.5.1.1 In-Vessel Steam Explosion

The in-vessel steam explosion is essentially of exclusive interest to PWRs. The Steam Explosions Review Group (SERG) convened by the NRC in 1985 as SERG-1, and again in 1995 as SERG-2, focused on the alpha-mode CF (α -failure). The SERG considered in detail only the issue of in-vessel steam explosions for PWRs. For BWRs, the lower plenum design, largely and densely occupied by control rod guide tubes, is considered to be generically prohibitive of the large-scale events required for α -failure. This conclusion also applies to the ESBWR design.

19.2.3.3.5.1.2 Ex-Vessel Steam Explosion Effects

EVEs are energetic FCIs that are triggered from already premixed states developed as the melt released from the RPV falls into and traverses the depth of a water pool below. In BWRs, LDW designs have traditionally employed very large-height geometries, which, when flooded, form deep water pools below the reactor vessel. Furthermore, metallic melts, such as those expected in the ESBWR for low-pressure scenarios, are especially prone to energetic interactions. The result is pressure pulses that may reach the kilobar magnitude range, potentially capable of loading major structures to failure when large quantities of melt are involved, together with highly subcooled water.

Regarding the potential damage from EVE, the relevant structures are the reactor pedestal reinforced concrete wall and the BiMAC device.

Failure of the reactor pedestal, along with the steel liner on it, would constitute violation of the containment boundary. While at static condition, the load-bearing capacity of this structure is adequate; explosive-level pressures acting on millisecond time scales can produce sufficient concrete cracking, along with liner stretching and tearing, to compromise the leaktightness of the containment.

Failure of the BiMAC device, on the other hand, is defined as crushing of the pipes so that they cannot perform their heat removal function. Such failure would raise the possibility of continuing corium-concrete interactions, BMP, and containment pressurization due to noncondensable gases.

GEH calculated the fragility of the pedestal under impulse loading using the DYNA3D model, which has been verified and validated for problems of this type. The calculated strains show that, at an impulse load of 600 kPa-s (87.0 psi-s), incipient liner failure and noticeable concrete damage occur. For impulse loadings of 200 and 300 kPa-s (29.0 and 43.5 psi-s), the pedestal holds up well.

GEH carried out calculations for the BiMAC device with the same type of impulse loadings as those used for the reactor pedestal. At impulse loads around 200 kPa-s (29.0 psi-s), a thin portion of the BiMAC embedded pipes yields significantly; however, the remaining material remains basically intact, while the pipe cross-sectional area is still largely intact. This is considered as the level of incipient failure by crushing.

The applicant calculated ESBWR steam explosion impulse rates using the PM-ALPHA.L-3D and ESPROSE.m codes for water pool depths of 1, 2, and 5 m (3.28, 6.56, and 16.4 ft) with 100 K (279.7 degrees F) subcooling. With one exception, typical primary impulses on the bottom were approximately 100 kPa-s (14.5 psi-s), while on the side, the impulse magnitudes increase with pool depth from 40 to 150 kPa-s (5.80 to 21.76 psi-s). The loads from 1- and 2-m (3.3- to 6.6-ft) deep, highly subcooled pools are taken to bound loads from shallow, saturated pools.

Only the low-pressure-at-vessel-breach Class I and Class IV severe accidents have the potential for EVEs. Given the margin between the calculated applied impulses and the structural fragility of the pedestal, GEH concluded through the ROAAM process that pedestal failure by an EVE is physically unreasonable for pools less than 1.5 m (4.9 ft) deep. For accidents with subcooled water depth in the LDW greater than 1.5 m [4.9 ft], GEH stated that an appropriately conservative position would be one in which "integrity of both the liner and the concrete structure could be possibly compromised." In the PRA, this translates to CF for deep pool Class I and Class IV accidents.

The NRC performed independent calculations using the PM-ALPHA/ESPROSE.m computer code to assess the energetics of EVEs for the ESBWR (ERI/NRC-06-202, "Analysis of Ex-Vessel Fuel Coolant Interactions for ESBWR," issued July 2006). Fragilities were not recalculated. Calculations for a base case and four sensitivity cases (assessing different pool depths, vessel breach diameter, and core melt composition) were performed. These calculations produced values of wall (i.e., pedestal) impulse loads ranging from 4 to 60 kPa-s (0.6 to 8.8 psi-s). These values are clearly consistent with and support the GEH estimate of a large margin to CF from EVE for 99 percent of the Class I severe accidents. The basemat (i.e., BiMAC) impulse load was independently calculated to be 35 kPa-s (5.1 psi-s) for low pool depths. This is consistent with the GEH "negligible energetics" value and supports the PRA assertion that BiMAC failure is considered physically unreasonable for low-pressure core melt drops in pools less than 1.5 m (4.9 ft) deep.

19.2.3.3.5.1.3 Minimization of Ex-Vessel Steam Explosion Effects in the ESBWR

The principal element of the GEH ESBWR severe accident management approach to EVE is to minimize the likelihood of deep subcooled water pools in the LDW at the time of vessel failure,

including inadvertent spray operation, and to have a structural design capable of coping with the loads expected in cases in which moderate amounts of water (shallow, saturated pools) cannot be avoided.

Containment design prevents subcooled water, to the extent possible, from entering the LDW through the UDW, in particular, by the rerouting of GDCS overflow and by outfitting the wetwell spillover lines with squib valves, similar to those that activate the equalizer line. The BiMAC device activation system requires high-temperature thermocouples to detect core-melt arrival and to send signals to actuate opening of the LDW deluge lines (feeding off the GDCS pools), thus preventing premature flooding.

The BiMAC is designed to be functional immediately upon opening of the deluge lines. Thus, preflooding of the LDW is unnecessary, and the detailed design of the deluge line valve activation system is based on detecting melt arrival onto the LDW floor. This activation system is accessible both automatically and by operator action, and the required reliability is set at less than 1×10^{-3} failure per demand.

There is no ESBWR requirement to initiate drywell sprays, and the emergency procedure guidelines (EPGs) do not use drywell sprays. They appear only as options in the SAMGs. Section 19.2.3.3.9 of this report further discusses spray usage.

Section 21.4 of the PRA report, Revision 6, describes the detailed probabilistic framework, quantification of EVE loads, quantification of fragility to EVE, and prediction of failure probability caused by EVE. The results of the studies on pedestal loads and fragility for 1- and 2-m (3.3- and 6.6-ft) deep highly subcooled pools, taken to bound loads from shallow, saturated pools, indicate a large margin to failure, thus suggesting that in 99 percent of the Class I severe accidents in the ESBWR, pedestal failure by an EVE is physically unreasonable.

The following are the principal components of such a conclusion:

- An accident management strategy and related hardware features that prohibit large amounts of cold water from entering the LDW before RPV breach
- The physical fact that premixtures in saturated water pools become highly voided and thus unable to support the escalation of natural triggers to thermal detonations
- Reactor pedestal and BiMAC structural designs that are capable of resisting impulse loads resulting from steam explosion of over about 500 kPa-s (73 psi-s) and about 100 kPa-s (14.5 psi-s), respectively.

The remaining 1 percent refers to Class I accidents with deep (i.e., depth greater than 1.5 m [4.9 ft]) subcooled water pools that constitute about 1 percent of the CDF. For such pools, although not considered in any detail, an appropriately conservative position would be that integrity of both the liner and the concrete structure could be possibly compromised. Similar conclusions are drawn for the BiMAC function. The 1.5-m (4.9-ft) demarcation for the “deep” water pool was selected because of the position of the hatch door, combined with a collective judgment aimed to exclude ranges of conditions that GEH does not believe could be reasonably captured by current capabilities and experience.

19.2.3.3.5.2 Conclusion

The staff concludes that in-vessel steam explosions are not a threat to the ESBWR containment based on the findings of the SERG. The staff finds the assumption that the occurrence of the flooded LDW at RPV failure leads directly to CF to be acceptable and conservative.

GEH states that the frequency of a flooded LDW at the time of reactor vessel failure is on the order of 10^{-9} per reactor-year. This provides a sufficient basis to conclude that the frequency of an EVE leading to CF has been reduced to an acceptably low value and is therefore acceptable.

GEH performed analyses to determine the capability of the ESBWR containment to withstand EVEs for essentially all other cases (with LDW water levels below 1.5 m [4.9 ft] and saturated water), even though failure in these cases is deemed physically unreasonable. The staff previously performed separate analyses for the ABWR design to justify a similar conclusion for that design. (See ERI/NRC-93-203, "Analysis of Ex-Vessel Fuel Coolant Interactions for ESBWR," July 2006.)

19.2.3.3.6 Containment Bypass

In SECY-90-016, the staff concluded that a special effort should be made to eliminate or further reduce the likelihood of a sequence that could bypass the containment. In SECY-93-087, the staff stated that vendors should make reasonable efforts to minimize the possibility of bypass leakage and their containment designs should account for a certain amount of bypass leakage.

19.2.3.3.6.1 Staff Evaluation

19.2.3.3.6.1.1 Suppression Pool Bypass

The ESBWR PRA evaluates suppression pool bypass pathways. These potential pathways for the release of radioactive material do not receive the benefits of suppression pool scrubbing.

19.2.3.3.6.1.2 Logical Process Used To Select Important Design Features

GEH systematically reviewed the core cooling features that could prevent or mitigate containment bypass to determine their contribution to total CDF. The applicant identified those features that would increase the calculated CDF by more than a factor of 2, whether they failed or were not included in the design as important features. These features are evaluated below:

Drywell-Wetwell Vacuum Breakers

The PRA evaluates the consequence of a vacuum breaker failing to close or inadvertently remaining open.

Redundant MSIVs

If both MSIVs in any one main steamline fail to close, there will be a large bypass pathway, as compared to other potential bypass pathways, from the RPV to the TB. Therefore, the failure of two MSIVs to close in any one steamline would result in a higher consequence from a given postulated event. Depending on the event, the dual failure could result in a substantial offsite dose consequence.

Design and Fabrication of the SRV Discharge Lines

The discharges of the SRVs are piped downward through the drywell/wetwell vent wall and only emerge into the suppression pool below the pool surface. This configuration minimizes the potential for bypass of the suppression pool as a result of a break in one of these lines.

Normally Closed Sample Lines and Drywell Purge Lines

The sample lines and drywell purge lines are normally closed during plant power operation. If one or more of these lines are open when an event initiates, a potential bypass path exists. Depending on the event and the size and number of lines open, a substantial fission product release could result in a significant increase in the consequences of a given event.

Diverse RWCU System Isolation Valves

The probability of not isolating an RWCU line break outside containment is very low because of the inclusion of three automatic diverse isolation valves (in addition to a remote manual shutoff valve). Even though the exposed structures and safety-related equipment are designed for the loads and environment that could result from an unisolated break, there is some potential for failure. Furthermore, there is some potential that the operator will not properly control the reactor vessel water level during the recovery phase.

Other Less Important Plant Features

The applicant judged several plant features treated in the analysis to be much less important than those discussed above. As noted in the PRA, these include piping dimensions, the level of water in the suppression pool, the closing of the turbine bypass valve, the instrument check valves, and reliable seating of redundant feedwater and SLCS check valves.

Release categories breaks outside containment, BYP, and OPVB include scenarios that bypass the suppression pool. Their combined frequency contributes about 10 percent of the CDF for at power internal event sequences. In RAIs 19.2-6, 19.2-10, and 19.2-11, the staff requested further information on vacuum breaker performance pertaining to vacuum breaker design. The staff tracked RAIs 19.2-6, 19.2-10, and 19.2-11 as open items in the SER with open items.

Subsequently, GEH modified the design to include upstream isolation valves to prevent bypass leakage in the event that the vacuum breakers do not completely close. Redundant proximity sensors and temperature sensors are also provided to detect the closed position of the vacuum breakers. The documentation in DCD Tier 2, Revision 9, Table 19.1-1, explicitly references these changes. The issue of potential containment bypass resulting from vacuum breaker leakage is resolved. Therefore, RAIs 19.2-6, 19.2-10, and 19.2-11 and the associated open items are resolved.

In SECY-90-016, the staff stated that containment venting should be delayed for approximately 24 hours following the onset of core damage. The ESBWR design does not credit the use of containment venting for preventing CF. The analysis includes containment venting simply to mitigate the magnitude of radionuclide releases resulting from loss of CHR by forcing the pathway through the suppression pool. In virtually all circumstances, containment venting would not be initiated within the first 24 hours of core damage, as the containment pressure load at 24 hours would still be under the ultimate pressure capability expected of the containment.

19.2.3.3.6.2 Conclusion

The staff concludes that GEH performed a complete analysis to facilitate an understanding of the capability of the ESBWR containment to accommodate a range of bypass conditions.

19.2.3.3.7 Containment Vent Design

19.2.3.3.7.1 Staff Evaluation

The system designated in the ESBWR EPG to control containment pressure is the containment venting system (CVS). This particular operational usage is referred to as the manual containment overpressure protection subsystem.

The ESBWR CVS design includes ventlines from the suppression chamber air space connected to the rooms directly below the suppression pool. In the event that CHR fails or CCI continues unabated, these CVS lines are opened under manual control to vent the wetwell gas space to the environment. This forces the higher pressure drywell gases to transfer to the lower pressure wetwell through the open wetwell-drywell vent paths, all of which go through the suppression pool water.

In a core damage event initiated by a transient in which the vessel does not fail, fission products are directed to the suppression pool via the SRVs, ICS, or PCCS, scrubbing any potential release. After RPV failure, the fission products are carried into the pool directly when the pressure differential is sufficiently large to activate the wetwell-drywell vents.

The vent is included in the PRA MAAP 4.0.6 model by reflecting expected operator guidance to open a 5.1-cm (2-inch) line followed by a 30.5-cm (12-in.) line as needed to control pressure rise. The vent is not credited in the base sequences, but its effect is evaluated separately in Section 8.3 of the PRA report, Revision 6. For modeling purposes, it is assumed that venting would occur only if containment pressure reached 90 percent of the ultimate pressure capability. Depending on the sequence details, this limit would be reached after 24 hours into the accident.

GEH stated that this arrangement for venting is satisfactory because the line sizes are adequate, and the system has the requisite monitoring and control capabilities. The staff agrees that the line sizes are adequate and that the requisite monitoring can be put into place.

19.2.3.3.7.2 Conclusion

The applicant has included in the ESBWR design the capability to vent the containment. The staff has reviewed the design of the venting capability and concludes that it can be an effective feature for mitigating containment pressurization events that may challenge containment integrity.

19.2.3.3.8 Equipment Survivability

SECY-90-016 and SECY-93-087 require that a survivability evaluation consider “credible” severe accidents. Similarly, 10 CFR 50.34 requires that equipment survivability consider an accident with the release of hydrogen generated by the equivalent of a 100-percent fuel-clad metal-water reaction.

Appendix 8D of the PRA report, Revision 6 presents the equipment survivability analysis for the ESBWR. Equipment survivability is evaluated to demonstrate that necessary components and instrumentation will be functional in the severe accident environment so that the plant may be placed in a controlled, stable state.

19.2.3.3.8.1 Staff Evaluation

19.2.3.3.8.1.1 Equipment and Instrumentation Necessary To Survive

The ESBWR severe accident functional requirements are based on the conservative assumption that all severe accident scenarios result in RPV failure and that recovery of failed equipment is not credited. That is, if equipment is failed or unavailable at any time during the accident sequence, it will not be repaired or made available. Only those components within the containment boundary are subject to the severe accident environment. From this perspective, the mitigating functions necessary to place the ESBWR in a stable, controlled configuration have been considered. These functions include cooling of corium debris bed (LDW), cooling of corium debris bed (i.e., in UDW), containment isolation, containment pressure control by heat removal or venting, combustible gas control, and postaccident monitoring.

Table 19.2-1 in this report summarizes the plant systems that are required to carry out severe accident functions. The table also lists the system components that are subject to the severe accident environment.

19.2.3.3.8.1.2 Severe Accident Environmental Conditions

The applicant performed MAAP 4.0.6 simulations to predict containment conditions for three representative accident sequences (i.e., transient with and without reactor depressurization and no coolant injection and a medium LOCA in liquid line with no coolant injection, representing a low and a high reactor pressure and a LOCA sequence, respectively); conditions for a fourth sequence (main steamline break with no core injection, representing a 100-percent fuel clad-coolant interaction sequence) were calculated using conservative simplifying assumptions. Then, GEH developed composite curves of containment pressure and temperature over a 24-hour period to represent bounding severe accident conditions. The applicant estimated radiation levels after a severe accident using a simplified one-compartment model. It was assumed that releases of 100 percent of the core noble gases and 50 percent of the core halogens were instantaneous at the start of the accident. All noble gases and halogens were assumed airborne for the full calculation time period with no credit taken for suppression pool scrubbing or other removal processes, either natural or otherwise (leakage or purging).

The analyses showed that the bounding pressure curve levels off at approximately 0.86 MPa (124.7 psi) at 24 hours after onset of core damage. The calculated bounding UDW region temperature history indicates that, except for a short period, it does not exceed 6160 K (638 degrees F) and subsequently remains below 500 K (440 degrees F) for the duration of the scenario. Based on these results, GEH indicated that reasonable assurance is provided that the integrity of the UDW electrical penetrations will be maintained at bounding conditions of 644 K (699 degrees F) and 1.025 MPa (148.7 psi).

**Table 19.2-1. System Functions and Monitored Variables Needed
after a Severe Accident (from Table 8D2-1 of the PRA).**

FUNCTION	MONITORED VARIABLES
Cooling of Debris Bed (in LDW)	LDW Temperature Deluge Valve Status Indication Drywell Air Temperature GDCS Tank Water Level Drywell Sump Level
Cooling of Debris Bed (in UDW)	Drywell Air Temperature
Containment Isolation	Drywell Pressure Isolation Valve Position
Containment Pressure Control: Heat Removal	Drywell Pressure Wetwell Pressure Drywell Air Temperature
Containment Pressure Control: Venting	Drywell Pressure Wetwell Pressure
Combustible Gas Control	Drywell/Wetwell H ₂ Concentration Drywell/Wetwell O ₂ Concentration
Containment Water Level	Suppression Pool Level Drywell Sump Level
Containment Radiation Intensity	Containment Area Radiation Monitoring
Noble Gas and Effluents at Potential Release Points	Environment Release Point Monitoring

19.2.3.3.8.2 Conclusion

The applicant carried out a systematic evaluation of the capability of the equipment necessary to survive in a severe accident environment in the ESBWR and to demonstrate reasonable assurance of operability. In doing so, GEH considered physical location, design or qualification in comparison to the severe accident environment, timing of the required equipment function, nature of the required equipment function, duration of the severe accident condition, and material properties. The severe accident environment was established by evaluating credible representative severe accident scenarios from the PRA, as well as a nonmechanistic, 100-percent fuel-clad metal-water reaction. The evaluation was for a 24-hour period after onset of core damage.

Table 8D.4-2 of the PRA summarizes the evaluation of severe accident equipment capability. The evaluation provides reasonable assurance that the ESBWR equipment necessary to achieve a controlled, stable plant condition will function over the time span in which it is needed.

19.2.3.3.9 Non-Safety-Related Containment Spray

The SAMGs will not include the use of the drywell spray system, and the PRA Level 2 and Level 3 analysis does not include drywell sprays.

No detailed designs for the spray systems have been put forward. Several statements in DCD Tier 2, Revision 9, imply that there will be interlocks that must be overridden before the sprays can be used. This is acceptable because the PRA does not credit any benefit of the containment spray system on fission product.

19.2.3.4 Conclusion

The applicant has provided several important design features that contribute to the mitigation of severe accidents. The staff evaluated the impact of these features on risk and finds that these features can be effective in reducing the risk associated with severe accidents. The staff concludes that, in accordance with the Commission's objectives for new reactor designs, the applicant has reduced the significant risk contributors of existing operating plants by introducing appropriate and effective design features that contribute to the mitigation of severe accidents.

19.2.4 Containment Performance Capability

This section describes the staff's assessment of the ESBWR containment structural performance to resist loads induced by postulated beyond-design-basis severe accidents. The ESBWR containment design and structural characteristics are described in DCD Tier 2, Revision 9, Sections 3.8.1 and 3.8.2. DCD Tier 2, Revision 9, Chapter 19, and the PRA report, Revision 6, describe the severe accident assessments, including the containment performance under postulated beyond-design-basis accident scenarios. The staff reviewed the applicable sections of DCD Tier 2, Revision 9, relating to PRA-based SMA for the containment and the containment performance against overpressurization induced by beyond-design-basis severe accident loads.

The staff used the review criteria as described in Section 19.2.4.1 below to review and evaluate DCD Tier 2, Revision 9, and the supporting PRA report, Revision 6, and to determine the adequacy of the applicant's assessment of the containment structural performance. This section describes the GEH containment structural performance assessment and the staff's evaluation of that assessment.

19.2.4.1 Regulatory Criteria

The staff used the following relevant regulations and regulatory guidance documents to perform this review:

- General Design Criterion (GDC) 16, "Containment design," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," relates to the capability of the containment to act as a leaktight membrane to prevent the uncontrolled release of radioactive effluents to the environment.
- GDC 50, "Containment design basis," relates to the containment being designed with sufficient margin of safety to accommodate appropriate design loads.

- Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” to 10 CFR Part 50 relates to the quality assurance criteria for nuclear power plants.
- 10 CFR 52.47 requires that a design certification application contain the proposed ITAAC that are necessary and sufficient to provide reasonable assurance that, if the inspections, tests, and analyses are performed and the acceptance criteria met, a plant that incorporates the design certification is built and will operate in accordance with the design certification, the provisions of the Atomic Energy Act, and the NRC’s regulations.
- 10 CFR 50.44 requires the containment integrity to withstand pressurization induced by an accident that releases hydrogen generated from fuel clad-coolant reaction accompanied by hydrogen burning. In particular, 10 CFR 50.44(c)(5) requires the performance of an analysis using an analytical technique acceptable to the staff to demonstrate the containment integrity to withstand internal pressurization from an accident that releases hydrogen generated from the 100-percent fuel clad-coolant reaction.
- RG 1.70, “Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants,” Revision 3, provides guidance for meeting the 10 CFR 50.44(c)(5) requirement and specifies the following:
 - Steel containments meet the requirements of the ASME Code (edition and addenda as incorporated by reference in 10 CFR 50.55a(b)(1)), Section III, Division 1, Subarticle NE-3220, Service Level C Limits, considering pressure and dead load alone (evaluation of instability is not required).
 - Concrete containments meet the requirements of the ASME Boiler and Pressure Vessel Code, Section III, Division 2, Subarticle CC-3720, Factored Load Category, considering pressure and dead load alone.

At a minimum, the specific ASME Code requirements set forth for each type of containment will be met for a combination of dead load and an internal pressure of 0.31 MPaG (45 psig).
- 10 CFR 52.47(a)(27) requires that the applicant provide a description of a design-specific PRA and its results.
- SECY-93-087 and the Commission’s SRM provide guidance for meeting the deterministic CPG in the evaluation of the passive ALWRs as a complement to the CCFP approach. The expectation in SECY-93-087 with respect to the deterministic containment performance assessment is as follows:

The containment should maintain its role as a reliable, leaktight barrier (e.g., by ensuring that containment stresses do not exceed ASME Service Level C limits for metal containment or factored load category for concrete containments) for approximately 24 hours following the onset of core damage under the most likely severe accident challenges, and following this period, the containment should continue to provide a barrier against the uncontrolled release of fission products.
- SECY-93-087, Section II.N, and the Commission’s SRM also provide guidance for a sequence-level SMA. PRA insights will be used to support a margin-type assessment of seismic events. A PRA-based SMA will consider sequence-level HCLPFs and fragilities for all sequences leading to core damage or CF up to approximately 1.67 times the ground motion acceleration of the design-basis SSE.

The staff has used applicable guidance from SRP Section 19.0, Revision 2.

19.2.4.2 Summary of Technical Information

In DCD Tier 2, Revision 9, Section 3.8, GEH described the physical characteristics of the concrete containment for the ESBWR plant. The containment is a reinforced concrete structure with a steel liner, and the containment pressure boundary consists of a foundation mat, cylindrical walls, RPV pedestal, suppression pool slab, girder-spanned top slab, and steel drywell head. Other internal structures that may be subject to severe accident loads include those located in the LDW and UDW areas, the vent wall separating the suppression pool, and the diaphragm floor supporting the GDCS pools. Severe accident loads may also affect the pressure capability of the drywell head, as well as the major containment penetrations (equipment hatch, personnel airlock, wetwell hatch), including penetrations for process piping and electrical cables.

The containment structure is designed to resist various combinations of dead loads; live loads; environmental loads, including earthquakes and those resulting indirectly from wind and tornadoes; normal operating loads; and loads generated by a postulated LOCA. The primary function of the containment structure is to provide the principal barrier to control potential fission product releases to the environment. The ESBWR primary containment is designed to withstand a maximum pressure of 0.310 MPaG (45 psig) and a design temperature of 171 degrees C (340 degrees F).

19.2.4.2.1 10 CFR 50.44 Requirement

The regulation in 10 CFR 50.44(c)(5) requires that an analysis be performed to demonstrate the containment structural integrity against loads generated by an accident that releases hydrogen from 100-percent fuel clad-coolant reaction accompanied by hydrogen burning. Section 8 of the PRA report, Revision 6 provides an evaluation of the ability of the ESBWR containment to withstand system-related containment challenges associated with potential combustible gas deflagration, overpressurization, and bypass. The ESBWR design employs an inerted containment, and GEH radiolytic oxygen concentration analysis, which assumes a 100-percent fuel clad-coolant reaction, showed that the time for the oxygen generation to increase to the deinerting value of 5 percent by volume following a severe accident is significantly greater than 24 hours. Therefore, there is sufficient time for implementation of severe accident management actions. GEH concluded that the CF caused by combustible gas deflagration is unrealistic. GEH also estimated the containment pressure induced by the hydrogen buildup to be 0.987 MPaG (143 psig) and performed a detailed containment structural analysis as described below.

DCD Tier 2, Revision 9, Appendix 19B provides a detailed finite element analysis to estimate the containment structural capacity using the guidance of RG 1.70, Revision 3. GEH assessed the containment performance to withstand the pressure and temperature loads resulting from the containment hydrogen buildup, assuming 100-percent fuel clad-coolant reaction, and estimated the containment pressure capability in terms of ASME Service Level C or factored load limits to be 1.011 MPaG (146.5 psig), which is adequate to withstand the pressure load of 0.987 MPaG (143 psig) resulting from 100-percent fuel clad-coolant reaction. GEH also identified the limiting component as the RCCV liner strain at the connection of the UDW wall and the top slab.

19.2.4.2.2 SECY-93-087 Deterministic Containment Performance Expectation

DCD Tier 2, Revision 9, Appendix 19B also addresses the SECY-93-087, Section I.J, expectation regarding the deterministic containment performance assessment against the pressure and temperature loads generated for the more likely accident scenarios, which GEH defined as sequences accounting for an aggregated 97 percent of CDF. The pressures and temperatures for these sequences were determined to be enveloped by the sequence T_nDP_nIN_TSL, a Class III sequence with peak pressure which was revised up to 0.87 MPaG (126 psig) from 0.62 MPaG (90 psig). GEH assessed the pressure capability of the containment structure following the guidance of SECY-93-087 and determined that the containment Level C (or factored load) limit is much higher than 0.62 MPaG (90 psig) pressure load taking into account the temperature effect on the material strength.

19.2.4.2.3 Probabilistic Containment Performance Assessment

GEH developed the containment pressure fragility in DCD Tier 2, Revision 6, Appendix 19C. The containment fragility is used in the Level 2 PRA and severe accident assessment of the containment phenomena. The containment pressure fragility was established with the aid of a detailed ABAQUS/ANACAP-U three-dimensional finite element containment model. The analysis also quantified the uncertainty associated with material properties and defined the failure criteria or limit states for estimating containment failure pressure capacity. Median capacity was calculated by setting all parameters to their median values.

The uncertainty in material properties and failure criteria was assessed by computing the 95-percent confidence value of a specific parameter, assuming a lognormal distribution, while keeping all other parameters at the median values. The containment failure pressure was also assumed as a lognormal distribution. Thus, the uncertainty in the failure pressure caused by the uncertainty of a parameter (either a material property or a failure criterion) can simply be determined using the relation, $\beta = \ln(P_{95}/P_m)/(-1.645)$, where P_{95} is the pressure capacity when evaluated using the 95-percent confidence value, and P_m is the median pressure capacity determined by using the median values of all the key parameters. The uncertainty can then be aggregated for all parameters using the square root of the sum of the squares (SRSS) method.

The modeling uncertainty (e.g., mesh fidelity, element formulations, robustness of the constitutive models) was assessed based on past experience and analyst judgment. The uncertainty was further increased to account for the various thermal conditions. The modeling uncertainty was then combined with the random uncertainty using SRSS, resulting in the containment pressure fragility.

Section 19.3 of DCD Tier 2, Revision 9, describes the containment phenomenological challenges such as DCH, EVE, and BMP and the containment response assessment. Chapter 21 of the PRA report, Revision 6, provides the detailed treatment of the containment phenomenological challenges and the corresponding containment responses, based on the ROAAM methodology.

DCH occurs when high-velocity steam from an RPV high-pressure blowdown impinges upon melt debris already released onto the LDW floor, thus creating a finely atomized melt mixture. The atomized hot melt is then dispersed into and heats up the UDW. In Section 21.3 of the PRA report, Revision 1, GEH stated that the set of accidents that could lead to DCH involve core degradation and vessel failure at high primary system pressure and the probability of such events occurring is very small (i.e., 2.8×10^{-9}). The Level 1 PRA also indicates that high-

pressure accidents contribute only about 1 percent of the CDF. The containment pressure load induced by a DCH event was estimated to be 0.7 MPa absolute (100 psi absolute), which intercepts the containment pressure fragility at very low probability (much less than 10^{-5}). GEH concluded that a DCH event in the ESBWR is physically unreasonable and categorized the DCH events discussed in Section 21.3 of the PRA report, Revision 1, as remote and speculative.

EVE events are energetic FCIs, which are triggered by melt released from the lower RPV head breach falling into a preexisting subcooled water pool in the LDW cavity. EVE events develop pressure impulses (the time-integral of the pressure load), which could damage LDW structures, such as the pedestal, and the BiMAC device.

In Section 21.4 of the PRA report, Revision 4, GEH described the containment and BiMAC performance against an EVE. The relevant structures subject to potential damage are the 2.5 m thick (8.2 ft) reinforced concrete reactor pedestal and the BiMAC device. The conditions for EVE are the presence of water and lower RPV pressure (low pressure, defined as RPV pressure less than 1 MPa [145 psi]). In the GEH analysis, the water depth is divided into three categories—high (H greater than 1.5 m [4.9 ft]), medium (H between 0.7 and 1.5 m [2.3 and 4.9 ft]) and low (H less than 0.7 m [2.3 ft]), where H is the depth of the subcooled water pool in the LDW cavity. For the high-level depth of the subcooled water pool, which involves only 0.9 percent of CDF, the failures of the structures involved are considered possible. For the other two water depths, which constitute 99 percent of CDF, GEH performed DYNA-3D analyses of the pedestal and BiMAC, concluding that the pedestal is capable of resisting pressure impulses of over 500 kPa-s (72.5 psi-s), and the BiMAC can sustain a pressure impulse of over 100 kPa-s (14.5 psi-s), the maximum pressure impulses induced by the EVE events. Therefore, 99 percent of the low-pressure sequences (Class I) can be excluded for the EVE evaluation. Based on the analysis results, GEH concluded that, for all but 1 percent of the CDF, violations of the containment integrity and BiMAC function are considered physically unreasonable.

The BMP events involve any amount of melt debris that is not coolable, and the decay power is split between the upwards (into water) and downwards (into concrete) directions. Both high-pressure and low-pressure scenarios need to consider BMP. In Section 21.5 of the PRA report, Revision 6, GEH describes the design of the BiMAC device, especially the selection of a refractory concrete material that serves as a protective layer, eliminating ablation by superheated melts and preventing BMP of the molten core debris for a minimum of 24 hours and hence preventing the CF.

19.2.4.2.4 Drywell Head

In DCD Tier 2, Revision 9, Section 3.8.2, GEH describes the drywell head as a removable steel torispherical shell structure that covers the opening in the containment's UDW top slab, directly above the RPV. The head is designed for removal during reactor refueling, using the RB crane.

DCD Tier 2, Revision 0, Section 6.2.5.4.2, presented a detailed deterministic analysis of the Level C internal pressure capacity for the drywell head at ambient temperature. This estimate is based on a design equation proposed by Equation (6.2-2) in Galletly, "A Simple Design Equation for Preventing Buckling in Fabricated Torispherical Shells under Internal Pressure," issued August 1979. The Galletly equation was qualified based on a comparison to 43 test results. GEH had previously performed a statistical analysis of the test data on which Equation (6.2-2) is based and documented it in the ABWR DCD. GEH identified the critical

location to be the knuckle region of the torispherical geometry. The calculated Level C pressure capacity is equal to 1.182 MPa (171.4 psi); circumferential buckling of the knuckle region is identified as the failure mode.

GEH reevaluated the Level C capacity of the drywell head in DCD Tier 2, Revision 1, Appendix 19B by calculating the Level C/factored load capacity in accordance with ASME Code, Section III, Divisions 1 and 2. The buckling failure of the head shell was precluded because of a low diameter/thickness ratio ($D/t = 260$), which was confirmed by a detailed finite element analysis. The applicant determined the governing pressure for the drywell head to be 1.033 MPaG (150 psig), which is controlled by the lower flange plate of the anchorage.

In Appendix B.8 to the PRA report, Revision 1, GEH presented a fragility analysis to determine the structural capability of the drywell head under internal pressure and temperature loading. GEH analyzed the pressure capacity of the head shell under ambient temperature, based on Equation (B.8-1) (from Shield and Drucker, "Design of Thin-Walled Torispherical and Toriconical Pressure-Vessel Heads," issued June 1961) for plastic yielding failure mode and the Galletly Equation (B.8-3). GEH determined that the Shield and Drucker Equation (B.8-1) governs the pressure capacity of the head shell for plastic yielding failure mode. GEH stated that, during various accident conditions, the ESBWR containment could be challenged by high temperature, with a typical accident temperature of about 533 K (500 degrees F). To obtain a more realistic estimate of the structural strength of the head shell, GEH increased the minimum yield strength of the shell material SA-516, Gr. 70, at 533 K (500 degrees F) by 10 percent. On the basis of the Shield and Drucker Equation (B.8-1), GEH estimated the ultimate pressure capacity of the drywell head at 533 K (500 degrees F) to be 1.204 MPaG (174 psig), with plastic yielding as the failure mode. GEH also stated that the containment ultimate pressure capability is limited by failure of the drywell head.

GEH further stated that a separate equation (B.8-10) by Galletly and Radhamohan, "Elastic-Plastic Buckling of Internally-Pressurized Thin Torispherical Shells," issued August 1979, and Galletly and Blachnut, "Torispherical Shells Under Internal Pressure—Failure Due to Asymmetric Plastic Buckling or Axisymmetric Yielding," provided a lower estimate of the shell pressure capacity than did the Shield and Drucker Equation (B.8-1). Therefore, the applicant used the Galletly Equation (B.8-10) to estimate the median pressure capacity of the drywell head, which is 1.623 MPa (235.3 psi) at 533 K (500 degrees F). GEH also estimated a composite logarithmic standard deviation of 0.16 for the shell material SA-516, Gr. 70. Based on the lognormal distribution, GEH stated that the containment pressure strength at 2 logarithmic standard deviations below the mean is 1.111 MPa (161.1 psi), or 3.58 times the design pressure (P_d) of 0.31 MPaG (45 psig), governed by the plastic yielding of the drywell head shell.

The applicant later revised the fragility analysis in DCD Tier 2, Revision 4, Appendix 19C based on a detailed finite element model. This analysis determined that the bending or prying deformation response in the bolted flanges stretches bolts to yield, leading to the failure of the head, according to the established failure criteria. The applicant determined the 95-percent confidence value for the failure pressure to be 1.443 MPaG (209.2 psig) at 533 K (500 degrees F), which is 4.65 times P_d .

The failure pressure was further revised in DCD Tier 2, Revision 5, Appendix 19C as 1.374 MPa (199.3 psi) ($4.43 P_d$) at 533 K (500 degrees F) with a 95-percent confidence level. The corresponding failure mode was identified by the tensile yielding of the flange anchor bolts.

The drywell head seals the cylindrical top portion of the UDW. The outside surface of the drywell head is immersed in a water pool during normal operation. The function of the water pool is to provide shielding for radiation. The water pool is isolated from other cooling pools (e.g., IC/PCCS pools). The pool is periodically replenished during normal operation. The presence of this water pool limits the temperature increase through the thickness of the drywell head, condenses steam accumulated on the inside surface of the head, and provides significant scrubbing of the fission products released through failed drywell head seals. GEH stated in Section 21.3.4.4 of the PRA report, Revision 1, that bounding estimates of this process yield internal drywell temperatures of less than 450 K (351 degrees F). GEH also expected that this cooling by the water pool would be effective in the long term and sufficient to accommodate the thermal loads from the hot UDW atmosphere, as it may develop during a DCH event.

19.2.4.2.5 Reinforced Concrete Containment Vessel

In DCD Tier 2, Revision 9, Section 3.8.1, GEH describes the RCCV as a cylindrical reinforced concrete structure with an internal welded steel plate liner. The liner is made of carbon steel, except for the wetted surfaces of the suppression chamber and GDCS pools, where stainless steel or carbon steel with stainless steel cladding will be used. The RCCV is surrounded by and structurally integral with the reinforced concrete RB through the floor slabs, the IC/PCC pools, and the service pools used for storage of the dryer/moisture separator and other components.

In DCD Tier 2, Revision 0, Section 6.2.5.4.2, GEH evaluated the Level C (factored load) pressure capability of the RCCV using the liner strain limits for factored load category specified in ASME Code, Section III, Division 2, Table CC-3720. GEH estimated the maximum liner strain from a nonlinear finite element analysis of the containment concrete structure, including liner plates, for internal pressure loading. No reference is provided for the analysis. GEH stated that the maximum strain is only 0.165 percent in tension when the internal pressure reaches 1.468 MPa (212.9 psi), which is higher than the 1.182 MPa (171.4 psi) pressure for the drywell head.

In Appendix B.8 to the PRA report, Revision 1, GEH presented an ANSYS axisymmetric finite element analysis of the RCCV subject to internal pressure and dead load at ambient temperature. The applicant scaled down the ultimate pressure capability values resulting from the ANSYS analysis by 10 percent to represent the pressure capability of the RCCV at 533 K (500 degrees F). Table B.8-2 summarizes the calculated pressure capacities of various RCCV components. The ANSYS analysis determined the pressure capacity of the RCCV to be 1.468 MPa (215 psi) at ambient temperature. The failure mode is identified as a shear failure of the suppression pool slab at the junction with the containment wall.

The applicant revised both the Level C/factored load and fragility analyses for the RCCV, as discussed above, in Appendices 19B and 19C to DCD Tier 2, Revision 4. The new analyses were based on a separate three-dimensional ABAQUS/ANACAP-U finite element model and considered the temperature effect on material properties. Level C pressure capacity was not provided. However, to address SECY-93-087, GEH performed an analysis to calculate the RCCV response to the internal pressure of 0.62 MPaG (90 psig) corresponding to the more likely severe accident conditions. The induced stresses and strains within the RCCV were found to be less than the Level C (factored load) allowable limits. If the internal pressure is increased to 0.987 MPaG (143 psig), corresponding to the 100-percent fuel-coolant reaction pressure, the liner in the UDW wall connection with the top slab will undergo 0.72-percent tensile strain, exceeding the factored load allowable of 0.3 percent. DCD Tier 2, Revision 9,

Appendix 19B identifies it as a local peak strain due to the membrane and bending effect for which the Level C strain limit is 1 percent.

19.2.4.2.5.1 Severe Accident Temperature Loads

Section 8.3 of the PRA report, Revision 6, describes the temperature loads for the RCCV induced by the more likely severe accidents. This section provides the temperature transient time histories for the RCCV for two system-initiated sequences—T_nDP_nIN_TSL and T_nIN_nCHR_FR. T_nDP_nIN_TSL represents a sequence in which no short- or long-term injection is available, with TSL being the only mode of fission product release.

T_nIN_nCHR_FR denotes the sequence in which both vessel injection and CHR functions are unavailable. Containment venting needs to be implemented to limit the containment pressure rise and to control the radionuclide release point. For both sequences, Section 8.3 of the PRA report, Revision 6, provides only the temperature time histories for the LDW, which show the steady-state temperature to be nearly 450 K (350 degrees F).

Another source of high-temperature loading on the RCCV is from a DCH event. DCH is a phenomenological event postulated for high-pressure core melt ejection from an RPV lower head penetration failure. In DCD Tier 2, Revision 9, Section 19.3.3, and Section 21.3 of the PRA report, Revision 6, GEH characterizes the potential for a DCH event to occur as remote and speculative. DCH events are not grouped in the category of the more likely severe accident scenarios for the ESBWR. In DCD Tier 2, Revision 9, Section 19.3.3, and Section 21.3 of the PRA report, Revision 6, GEH discusses in a hypothetical context a CF caused by DCH events. The applicant indicated that, in the event of an RPV failure at high pressure (above 1 MPa [145 psi]), the superheating of gases generated within a timeframe of 40 to 80 minutes following core uncovering can lead to temperature levels of approximately 1,000 K (1,300 degrees F) in the upper RPV area. After taking credit for vent clearing from the UDW into the heat sink of the wetwell, the drywell temperature would be reduced to 800 K (980 degrees F). However, GEH pointed out that the necessary condition for a DCH event to occur requires that a minimum of two out of four ICs fail because of either water depletion on the secondary side or failure to open the condensate return valves. In addition, all 8 of the DPVs and 18 of the SRVs must fail. GEH indicated that it assessed the probability of such a combination of events to be 2.8×10^{-9} /yr. Therefore, GEH concluded that a DCH event is physically unreasonable.

19.2.4.2.5.2 Environment Loads—Seismic: Estimates of Containment Seismic Fragility

In DCD Tier 2, Revision 0, Section 19.2.2.4, GEH summarized an SMA for Category I structures, including the RCCV. In DCD Tier 2, Revision 1, the bulk of the summary description in Revision 0 was removed and replaced with a brief description in DCD Tier 2, Revision 1, Section 19.2.3.5, which also included a table of the qualitative structural HCLPF capacities.

Section 15 of the PRA report, Revision 6, describes in detail both the method and resulting HCLPF values for Category I structures. The applicant determined the plant HCLPF value from the SSC HCLPF values using the MAX-MIN method.

In Section 15 of the PRA report, Revision 6, GEH describes the SMA performed for seismic Category I structures and presented respective HCLPF values, including the RCCV. The Zion method in NUREG/CR-2300, "A Guide to the Performance of Probabilistic Risk Assessments for Nuclear Power Plants," issued January 1983, was applied to the seismic fragility calculations. The applicant calculated the seismic HCLPF for the containment to be 1.4g with the shear failure mode. The lowest HCLPF value for other structural components of the RCCV

is estimated to be 0.62g, controlled by channel deflection in the fuel assemblies. Thus, GEH determined the plant seismic HCLPF to be 0.62g.

The design SSE for the ESBWR is governed by the spectrum discussed in RG 1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants," anchored at 0.3g PGA, and the North Anna early site permit (ESP) site-specific SSE spectrum. In accordance with the soil-structure interaction analysis described in Appendix 3A to DCD Tier 2, Revision 9, generic sites with 0.3g input (per RG 1.60) typically result in higher structural responses than the North Anna ESP conditions for building structures, including the containment. Therefore, GEH used the RG 1.60 spectrum anchored at 0.3g PGA for the design seismic load calculation.

The applicant used the NUREG/CR-0098, "Development of Criteria for Seismic Review of Selected Nuclear Power Plants," issued May 1978, median spectrum shape for fragility calculations and described various safety factors established between the NUREG/CR-0098 spectrum and the RG 1.60 spectrum. Table 15-3 of the PRA Report, Revision 6, presents the final fragility for the RCCV wall. GEH demonstrated that the ESBWR containment meets the SECY-93-087 expectation for the seismic margin assessment. The sequence-level HCLPF is at least 1.67 times SSE (0.5g PGA). The HCLPF value for the RCCV is 1.20g PGA, with the failure mode characterized as shear failure of the containment lower wall.

DCD Tier 2, Revision 9, and the PRA report, Revision 6, develops a performance-based design spectrum, which is the same as the single certified design spectrum at 9 hertz (Hz) and above. For lower frequencies, the applicant used a spectrum shape that bounds all the soil sites except Vogtle. Therefore, the performance-based design spectrum falls below the single certified design spectrum for frequencies below 9 Hz, which affects the HCLPF capacity calculations for soil sites.

Based on the performance-based design spectrum, GEH performed a PRA-based SMA, which determined that the sequence-level HCLPF is at least 1.67 times the SSE tied to the performance-based design spectrum.

19.2.4.2.5.3 *Containment Liner—Failure of Pressure Containment Function During Severe Accident Loadings*

In DCD Tier 2, Revision 0, Section 6.2.5.4.2, and Appendix B.8 to the PRA report, Revision 1, GEH discussed the structural capacity of containment liner plates when the internal pressure is as high as 1.468 MPaG (215 psig). The maximum liner strains are found to be well within the ASME Code allowable values for factored load category. GEH also stated that the liner plate analysis indicated no tearing at the severe accident pressure of 1.204 MPaG (174 psig). The most significant effect of thermal loading on the liner is a potential buckling failure if the internal pressure-induced liner tensile stress is insufficient to overcome the thermal-induced compressive stress. Therefore, the potential for thermal-induced liner buckling can be examined only within the context of the containment pressure and temperature time histories associated with the more likely severe accident scenarios. GEH estimated that a typical severe accident temperature for the ESBWR component is 533 K (500 degrees F). At this temperature, GEH concluded that the ESBWR liner would not fail, given a containment internal pressure of 1.204 MPaG (174.6 psig).

In DCD Tier 2, Revision 4, Appendix 19B the GEH new Level C analysis estimated that the liner strain will exceed the Level C allowable limit for internal pressure of 0.987 MPaG (143 psig)

unless the thermal-induced compressive liner strain is included, which reduces the level of tensile strain in the liner.

For the fragility analysis, as documented in DCD Tier 2, Revision 4, Appendix 19C the failure criteria for liner strain at a 95-percent confidence level was established at 2.04 percent at 260 degrees C (500 degrees F), and the corresponding 95-percent failure pressure for RCCV was calculated to be 1.317 MPaG (191.0 psig) (4.25 P_d), governed by the liner tear at the RCCV wall connection with the top slab.

Although GEH characterized DCH events as unlikely accident scenarios, uncertainty about such event estimates is large. Therefore, GEH performed a reactor analysis to estimate the DCH-induced containment temperature and a structural analysis to evaluate the potential for thermal-induced liner failures. Based on the reactor analysis described in Section 21.3 of the PRA report, Revision 1, the DCH-induced UDW temperatures are estimated to be about 1,000 K (1,300 degrees F); however, for very short periods (less than 1 second), GEH estimated that the LDW could experience very high temperatures of up to 4,000 K (6,740 degrees F). A DYNA-3D analysis shows that a liner with concrete backing can sustain high temperatures up to 1,650 K (2,510 degrees F), and the calculated thermal strains are about 8 percent.

19.2.4.2.5.4 Penetrations—Failure of Pressure Containment Function during Severe Accident Loadings

In Sections 8.2 and B.8.2.2.2 of the PRA report, Revision 1, GEH discussed the major penetrations, such as the drywell head closure, equipment hatches, and personnel airlocks. The penetrations have a high potential for leakage under severe accident conditions. Leakage through fixed penetrations for process piping and electrical cables is assumed to be less likely. The seal performance depends mainly on temperature, as well as the effect of thermal and radiation aging of seal materials. Test data for the sealing materials are used to qualify their performance under severe accident conditions. In addition, GEH presented a screening analysis to identify penetrations that could potentially lead to offsite consequences. Appendix C.8 to the PRA report, Revision 1, details the penetration screening analysis.

Appendices 19B and 19C to DCD Tier 2, Revision 9, provide Level C and fragility evaluations of equipment hatches and personnel airlocks, based on the new ABAQUS/ANACAP-U three-dimensional finite element models. The new analyses conclude that these main penetrations have much higher Level C and fragility in terms of the 95-percent values than do the RCCV and drywell head.

19.2.4.2.6 Reactor Cavity Structures

In DCD Tier 2, Revision 1, Section 19.3.4, and Sections 21.4 and 21.5 of the PRA report, Revision 1, GEH discussed the structural components that would be affected by potential EVEs and BMP. These include the reactor pedestal, reinforced concrete basemat, and BiMAC device. EVE is a postulated internally initiated event of energetic FCIs. An EVE is triggered as the core melt released from the failed RPV lower head falls into and traverses the depth of an already existing water pool on the LDW floor. EVE events result in energetic pressure pulses, with magnitudes in the kilobar range, which are potentially capable of loading major structures to failure when large quantities of melt react with highly subcooled water. The EVE loading is characterized by the impulse (the time-integral of the pressure) acting on the surface of a structure.

BMP events involve any amount of melt debris released onto the LDW floor that is not coolable. The decay power is split between the upward (into water) and downward (into concrete) directions. Both high-pressure and low-pressure scenarios need to consider BMP. The potential effect of BMP is CCI.

19.2.4.2.6.1 *Reactor Cavity—Structural Performance under Ex-Vessel Steam Explosion Loadings*

In DCD Tier 2, Revision 0, Section 19.3.4, and Section 21.4 of the PRA report, Revision 1, GEH discussed potential damage to structures caused by EVE loadings. The reactor cavity is enclosed by the reactor pedestal on the side and basemat on the bottom. Failure of the reactor pedestal, along with the steel liner on it, constitutes violation of the containment boundary. The GEH assessment includes using PM-ALPHA-3D to quantify the EVE loadings and an LS-DYNA3D analysis to determine the structural response of the pedestal and its liner. GEH concluded that failures of the reactor pedestal and the steel liner induced by steam explosions are physically unreasonable.

The conditions for EVE are the presence of water and lower RPV pressure (low pressure). The GEH analysis divides the water depth into three categories—high (H is greater than 1.5 m [4.9 ft]), medium (H is between 0.7 and 1.5 m [2.3 and 4.9 ft]) and low (H is less than 0.7 m [2.3 ft]). H is the depth of the subcooled water pool in the LDW cavity, measured from the bottom of the reactor cavity. For the high-level depth of the subcooled water pool, which involves only 0.9 percent of CDF, failure of the affected structures is considered possible. For the other two water depths, which constitute 99 percent of CDF, GEH performed a DYNA-3D analysis for the pedestal and concluded that the pedestal is capable of resisting a pressure impulse of more than 500 kPa-s (72.5 psi-s). For the high-water depth (H = 1.5 m [4.9 ft]), there is a 2.2-m (7.2 ft) gap between the top of water and the bottom of the pedestal penetration; therefore, it is unlikely that an EVE event could affect the penetration. On the basis of the analysis results, GEH concluded that, for all but less than 1 percent of CDF, violations of the containment integrity are considered physically unreasonable.

19.2.4.2.6.2 *BiMAC Device—Structural Performance under Ex-Vessel Steam Explosion Loadings*

In DCD Tier 2, Revision 9, Section 19.3.4, and Sections 21.4 and 21.5 of the PRA report, Revision 6, GEH discusses the performance of the BiMAC in the LDW affected by EVE loading. The BiMAC device comprises thick-walled steel pipes covered by a layer of protective material with properties to resist very high heat. GEH stated that the protective layer is designed to prevent melt impingement due to corium ablation, thus maintaining containment integrity. In addition, the BiMAC cavity has a volume of about 400 percent of the full-core melt debris. Therefore, no possibility exists for the released melt to remain in contact with the reactor pedestal.

The GEH assessment included use of the PM-ALPHA-3D code to quantify the EVE loadings and an LS-DYNA3D analysis to determine the structural response of the BiMAC device. GEH concluded that violation of the BiMAC function caused by EVE is physically unreasonable.

19.2.4.2.6.3 Reactor Pedestal/Vessel Supports—Structural Performance Given Failure of BiMAC and Continued Core-Concrete Interactions

In NEDO-33201, Revision 6, Section 21.4.2, GEH stated that failure of the reactor pedestal, along with the steel liner on it, would constitute a violation of the containment boundary. As discussed in Section 19.2.3.3.3 above, such failures are highly unlikely because water would be poured onto the debris after vessel breach and the BiMAC would function to cool the debris from below as well. If the BiMAC functions properly, there would be very little erosion of the pedestal wall over a 24 hour period, and only about 0.5 m (1.6 ft) of sacrificial concrete would be eroded from downward attack from molten core debris during representative severe accident sequences, as shown by GEH in Section 8.3 of Revision 6 of the ESBWR PRA.

If the LDW deluge system doesn't provide sufficient water, and/or the BiMAC does not function properly, then significant radial and axial erosion of concrete would result, such that pedestal failure would occur. In the response to RAI Question 19.2-32, GEH indicated that the lower limit for the amount of radial erosion that can be *sustained* without pedestal structural failure is 2.28 m (7.5 ft) of the 2.5 m (8.2 ft) ESBWR pedestal wall thickness. They reported a number of sensitivity cases for various depths of an overlying water pool (including a dry CCI case), considering both basaltic and limestone concretes, and varying the heat transfer coefficient between the core debris pool and the overlying water pool. The BiMAC was assumed to not function for these cases. The only cases where pedestal failure prior to 24 hours after accident initiation was predicted were for basaltic concrete: the dry CCI case; and a case where the heat transfer between the core debris pool and the overlying water pool was controlled to obtain a heat transfer rate of 200 kWt/m² (63,442 BTU/hr/ft²).

19.2.4.3 Staff Evaluation

The structural performance of the containment under severe accident loads reviewed by the staff encompasses: (1) the GEH assessment of the Level C (or factored load) pressure capability of the containment in accordance with 10 CFR 50.44(c)(5), (2) the GEH demonstration of the containment capability to withstand the pressure and temperature loads induced by the more likely severe accident scenarios as stipulated in SECY-93-087, Section I.J, (3) the GEH containment structural fragility assessment for overpressurization, and (4) the GEH seismic HCLPF assessment of the RCCV in meeting the SECY-93-087, Section II.N, expectation. The staff also reviewed the GEH assessment of the structural effects of postulated containment phenomenological challenges such as DCH and EVE loads on the containment. The review and evaluation described in this section were focused on the structural performance of the containment boundary as the ultimate barrier to radionuclide releases to the environment in a severe accident.

The staff reviewed relevant sections of DCD Tier 2, Revision 9, and the PRA report, Revision 6, to determine the adequacy and accuracy of the information provided with respect to the performance of various structural components of the containment pressure boundary under severe accident loads. The structural components of the containment that the staff evaluated included the drywell head, RCCV, and reactor cavity structures. The staff evaluation provided in the ensuing sections is based on (1) DCD Tier 2, revisions, and revisions of the PRA report, including the information in DCD Tier 2, Chapters 6 and 19, and relevant sections of the PRA report regarding the structural containment performance in the event of severe accidents and (2) the GEH responses to the staff's RAIs.

19.2.4.3.1 10 CFR 50.44 Requirements

GEH addressed the requirements of 10 CFR 50.44 in DCD Tier 2, Revision 9, Sections 6.2.5.4 and 6.2.5.5 as they relate to hydrogen combustion. Since the ESBWR containment is inerted, the staff finds that the burning of hydrogen in the containment is precluded. Further, a necessary condition to deinvert the containment is that the containment oxygen concentration increases to 5 percent by volume. DCD Tier 2, Revision 9, Section 6.2.5.5, describes the GEH analysis that determined the time required for the oxygen concentration to increase to the deinvert value of 5 percent. It is significantly greater than 24 hours for a wide range of events, including 100-percent fuel clad-coolant interaction. The staff finds the applicant's analysis to be appropriate and acceptable.

Although the ESBWR containment is inerted and is designed for a DBA pressure of 0.31 MPaG (45.9 psig) GEH estimated the containment pressure load resulting from the 100-percent fuel clad-coolant reaction to be 0.987 MPaG (143.2 psig), well above the design pressure.

Based on questions raised during the staff evaluation, GEH resubmitted a revised Level C containment pressure analysis, which is documented in DCD Tier 2, Revision 4, Appendix 19B. The applicant revised other sections of DCD Tier 2, Revision 4, that are related to Level C containment pressure capacity by reference to Appendix 19B.

The GEH Level C containment performance analysis was based on a new and more technically enhanced three-dimensional ABAQUS/ANACAP-U finite element analysis. The staff considers the approach acceptable because the model: (1) accounted for the structural characteristics unique to the ESBWR containment (many geometric discontinuities and nonsymmetric loads caused by GDCS pools and pool structures above the top slab, which an axisymmetric finite element model may be unable to capture), (2) properly considered material properties of the structural components, especially with respect to the high-temperature effect, (3) included sufficient mesh refinement to address local stress/strain concentrations, and (4) addressed uncertainty in both finite element modeling and modeling of material properties by using typical industry practice through a lognormal distribution model.

During its review, the staff identified an issue with the new ABAQUS/ANACAP-U analysis concerning the temperature boundary condition of 43.3 degrees C (110 degrees F) specified for the drywell head while the rest of the UDW airspace is kept at 260 degrees C (500 degrees F) in steady state. Since the drywell head airspace is separated from the drywell airspace only by the bellow, which is made of a steel plate, the staff questioned whether the head shell can be kept at 43.3 degrees C (110 degrees F) while the drywell airspace is assumed to be at 260 degrees C (500 degrees F) steady state. Because the refueling pool is located directly above the drywell head, which is kept from being submerged during a postulated beyond-DBA, overheating of the drywell head shell is prevented. The staff believes that the temperature for the drywell head should be determined through an appropriate heat transfer analysis. In RAI 19.2-41 S02, the staff asked GEH to address this issue. The staff tracked RAI 19.2-41 as an open item in the SER with open items.

In response to RAI 19.2-41 S02, GEH agreed with the staff that the temperature boundary condition was incorrectly specified for the drywell head in the containment pressure capacity analyses provided in DCD Tier 2, Revision 4, Appendices 19B and 19C. Based on venting channels between drywell and drywell head airspaces and more detailed MAAP 4.0.6 analyses, GEH modified the temperature under the drywell head from 43.3 degrees C (110 degrees F) to 260 degrees C (500 degrees F) and the temperature of water in the pools above the drywell

head from 43.3 degrees C (110 degrees F) to 100 degrees C (212 degrees F). GEH also updated Level C and pressure fragility analyses, which are provided in DCD Tier 2, Revision 5. The Level C pressure capacity was determined to be 1.011 MPaG (146.6 psig), controlled by the RCCV liner tensile strain (DCD Tier 2, Revision 4, identified the containment pressure capacity as being controlled by the drywell head). GEH has addressed the staff's concern regarding the temperature boundary condition for the drywell head. Based on the above discussion, the staff considers that the GEH response is adequate and acceptable, and RAI 19.2-41 S02, is closed. Therefore, RAI 19.2-41 and the associated open item are resolved.

The new ABAQUS/ANACAP-U analysis result shows that, at an internal pressure of 0.987 MPaG (143.2 psig), or 3.18 P_d, the strain in the liner of the UDW wall at the connection with the top slab reached 0.72 percent, which exceeds the factored load limit for liners (0.3-percent tensile membrane strain, ASME Code, Section III, Division 2, Subarticle CC-3720). The staff questioned the GEH justification for using the thermal-induced strain to reduce the liner strain within the factored load limit. RG 1.7 clearly states that the analysis should consider pressure plus dead load alone. Based on the information in Figure 19B-5 of DCD Tier 2, Revision 4, the excess liner strain appears to be a localized phenomenon (designated as "location A" in the figure). It is unclear from the text whether the applicant calculated the strain from the membrane or from the membrane plus bending. In RAI 19.2-86, the staff requested that GEH clarify how it calculated the strain. The staff tracked RAI 19.2-86 as an open item in the SER with open items.

In response, GEH addressed the staff's concern by performing the pressure capacity analysis with the appropriate temperature boundary conditions and identified the liner strains at locations where prominent geometric discontinuities are present and other locations away from any geometric discontinuity. GEH determined the Level C capacity of the liner in accordance with the criteria provided in ASME Code, Section III, Division 2, Subarticle CC-3720, for both membrane and membrane plus bending strain allowables. The staff finds that the GEH response is adequate and the GEH analysis is acceptable. Therefore, RAI 19.2-86 and the associated open item are resolved.

Based on the above discussion, the staff concludes that DCD Tier 2, Revision 9, Appendix 19B adequately addresses the containment Level C pressure capacity to withstand the pressure loads induced by considering a 100-percent fuel clad-coolant reaction, and therefore, meets the requirements of 10 CFR 50.44(c)(5).

19.2.4.3.2 SECY-93-087 Deterministic Containment Performance Expectation

The staff reviewed the GEH approach to addressing the expectation stated in SECY-93-087 for containment performance (i.e., by referencing a containment Level C pressure capacity analysis described in RG 1.7, Revision 3). During its review, the staff identified several issues that should be considered in addressing SECY-93-087, including (1) identification of the more likely severe accident sequences per SECY-93-087, (2) determination of the containment challenges resulting from the more likely severe accident sequences defined in terms of the transient pressure and temperature time histories (for both short term [up to 24 hours] and long term [up to 72 hours]), and (3) assessment of the containment performance to ensure an adequate margin of the containment Service Level C/factored loads pressure capacity against the severe accident challenges. The Level C containment pressure capability calculation should include the effect of elevated temperature on material properties.

GEH reviewed the accident sequences from the Level 1 PRA and identified the top 10 sequences contributing to CDF. GEH determined that the most likely (97 percent of the core damage sequences identified in the PRA) containment pressure and temperature time histories load resulted from the sequence T_nDP_nIN_TSL (transient with no injection and no depressurization with release category of TSL). The staff considers the selection of the sequence T_nDP_nIN_TSL acceptable, because it envelops the significant accident sequences as defined in RG 1.200, Revision 2. The initiating event for this sequence is a loss of offsite power. The sequence is in Class III. In Section 8.3 of Revision 4 PRA, the containment pressure load at 24 hours after onset of core damage is 0.62 MPaG (89.9 psig), and the long-term pressure is below 0.70 MPaG (101.5 psig). The steady-state temperature for this sequence is about 450 K (350 degrees F).

GEH calculated the Level C pressure capacity of the containment based on an axisymmetric ANSYS model and a set of empirical equations (see Sections 19.2.4.2.3 and 19.2.4 of DCD Tier 2, Revision 0). The staff identified several issues with the GEH approach and associated analysis model for the Level C pressure capacity determination of the containment, which Section 19.2.4.3.3 of this report discusses in detail.

To address the staff's concerns, GEH recalculated the Level C pressure capacity of the containment using a new analysis based on the three-dimensional ABAQUS/ANACAP-U containment structural model and applicable ASME Code equations. The new ABAQUS model uses the pressure and temperature profiles associated with the more likely severe accident sequences and includes detailed modeling of all structural components that make up the containment pressure boundary. During the staff's October 25-26, 2007, onsite audit (ML073231149), GEH presented the analysis model and results of a preliminary ABAQUS analysis of containment performance, which the staff finds to be appropriate, except for the temperature of 43.3 degrees C (110 degrees F) specified for the drywell head.

The Level C analysis results, as revised by GEH and described in DCD Tier 2, Revision 5, Appendix 19B show that, at an internal pressure of 0.62 MPaG (89.9 psig), or 2.0 P_d, peak strains in the liners of the RCCV were kept well below the factored load limit (0.3-percent tensile membrane strain, ASME Code, Section III, Division 2, Subarticle CC-3720). Furthermore, the GEH analysis in Table 19B-6 of DCD Tier 2, Revision 5, indicated that at 2.0 P_d, the induced stresses in RCCV rebar and concrete are significantly less than the ASME Code allowable stresses. In Section 8.3 of Revision 6 to the PRA, the containment pressure load at 24 hours after onset of core damage was revised for the sequence T_nDP_nIN_TSL up slightly to 0.87 MPaG (124.7 psig), or about 2.8 P_d. Since the analysis in DCD Tier 2, Revision 9, Appendix 19B, establishes the Level C pressure capacity of the RCCV and Liner system at a design pressure of 1.011 MPaG (146.5 psig), therefore, the staff concludes that the GEH deterministic containment performance analysis meets the expectation of SECY-93-087.

19.2.4.3.3 Probabilistic Containment Performance Assessment

GEH performed the containment performance assessment against overpressurization and developed the containment pressure fragility, which is used in the ESBWR Level 2 accident progression analysis. The fragility was developed based on a lognormal distribution, which the staff finds acceptable for the containment pressure capacity.

The use of a lognormal distribution requires a determination of the median values of failure pressure for various CF modes and consideration of the variability of the associated parameters. To this end, either a simplified fragility method or a sampling method such as

Monte Carlo can be used to establish the containment fragility. To apply the simplified fragility method, the median failure pressure for various CF modes is calculated first, and the variability (in both aleatory and epistemic terms) about the median failure pressure is then estimated. The sampling method is implemented using the following steps:

- (1) Identify all random variables associated with the estimate of the CF pressure.
- (2) Select the probability distribution for each random variable.
- (3) Perform a sampling analysis to determine the containment pressure fragility.

In DCD Tier 2, Revisions 0 and 1, and the PRA report, Revision 1, GEH applied the simplified method to establish the containment pressure fragility. GEH relied on an axisymmetric ANSYS finite element analysis of the RCCV and a set of empirical equations for the drywell head to conclude that the containment pressure capacity is controlled by the failure of the drywell head shell. The staff identified several issues with the ANSYS model, which may not be appropriate for capturing the correct CF mode under internal pressurization. Specifically, combining the stiffness of the upper slab and the girders, as well as the structures above the upper slab, precludes the determination of the failure of each individual component. The ANSYS model determined that a shear failure of the suppression pool slab near the RCCV wall governs the RCCV pressure capacity.

The staff also found that the set of empirical equations that GEH used for estimating the drywell head pressure capacity was questionable, given the configuration of the ESBWR drywell head shell. The staff noted that GEH based its equations on past studies by Galletly and Shield and Drucker for torispherical shells; however, the test database used to verify these equations is inappropriate for the ESBWR drywell head, which has a much smaller ratio of diameter to thickness of shell than those included in the test database. Therefore, use of the empirical equations significantly underestimated the pressure capacity of the drywell head shell.

To address the issue of determination of the containment pressure capacity using the ANSYS analysis and the set of empirical equations, GEH revised the estimate of the containment pressure capacity with a new analysis. The applicant documented the new analysis in Appendices 19B (deterministic) and 19C (probabilistic) to DCD Tier 2, Revision 5. The analysis performed was based on a new three-dimensional ABAQUS/ANACAP-U containment structural model. The new ABAQUS model used the pressure and temperature profiles associated with the more likely severe accident sequences and included detailed modeling of all structural components of the containment pressure boundary. During the staff's October 25-26, 2007, onsite audit (ML073231149), GEH presented the results of the ABAQUS analysis of containment performance, which the staff finds to be appropriate. The analysis identified several failure modes that likely control the containment pressure capacity. They are the tensile yielding failure of bolts for the bolted flange system for the drywell head and the shear failure of girders spanning the upper slab.

The GEH analysis for establishing the pressure fragility of the containment system consisted of "best estimate" (median) and uncertainty evaluation, based on a lognormal distribution model. The uncertainty evaluation was performed using the median and an estimate of 95th-percentile pressure capacities. The applicant considered three temperature conditions: (1) steady-state normal operating temperature (ambient), (2) steady-state long-term accident temperature (260 degrees C [500 degrees F]), and (3) transient thermal conditions for a temperature spike representative of DCH conditions (peak temperature at 538 degrees C [1,000 degrees F]). Both median and 95-percent confidence values were developed for the elastic and plastic material properties and failure criteria. For the three temperature conditions, the applicant assembled

material data using sources from published literature and NUREG reports. The staff finds that the GEH approach to containment fragility analysis represents a state-of-the-art approach, and both the material data collection and the establishment of the failure criteria for the containment system are reasonable.

In Section 8.3 of Revision 6 to the PRA, the containment pressure load at 24 hours after onset of core damage for the sequence T_nDP_nIN_TSL is 0.87 MPa (124.7 psi), or about 2.8 P_d. The analysis in DCD Tier 2, Revision 9, Appendix 19B, establishes the Level C pressure capacity of the RCCV and Liner system at a design pressure of 1.011 MPaG (146.5 psig).

Based on the above, the staff concludes that the applicant's containment performance analysis is acceptable.

19.2.4.3.4 Drywell Head

The staff noted that in the PRA report, Revision 0, the applicant determined the pressure capacity of the drywell head shell using several empirical equations, which were developed from past studies (Shield and Drucker; Galletly). The staff reviewed the test data, which were the basis for the Galletly Equation (B.8-3), against the parameters for the ESBWR drywell head, which has a D/t ratio of 260, r/D ratio of 0.173, L/D ratio of 0.9, and S_y = 288 MPa (41,760 psi) (D is the diameter of the cylinder, r is the radius of the knuckle, L is the radius of the sphere, and t is the shell thickness). Among these, D/t and r/D ratios have the most influence on the shell pressure capability. The test data that GEH used have a minimum D/t ratio of 357. For those test data that have the same r/D ratio as the ESBWR, the corresponding D/t ratio was found to be equal to 2325. Since the ESBWR drywell head shell has a D/t ratio that is well below the minimum D/t ratio found in the test data, in RAI 19.2-40 the staff questioned the applicant's use of the Galletly Equation (B.8-3) and test data to establish a buckling capacity for the drywell head shell.

In addition, given the high r/D ratio and low D/t ratio for the ESBWR drywell head shell, the torus section of the shell should be very stiff for resisting hoop compression, and the head should fail by inelastic tensile strain in the spherical cap area. For this reason, the staff questioned GEH's decision to base the pressure capability estimate for the drywell head shell on the empirical equations discussed above.

The GEH response to RAI 19.2-40 explained that the applicant had improved the design of the drywell head shell by adding a taper at the connection with the bolted flanges and the design of the head anchorage by increasing its stiffness. However, based on Tables 19.2-40(1) and 19.2-40(3), submitted as part of the GEH response, the staff questioned whether the drywell head pressure capacity should be controlled by failure of the shell or governed by the capacity of the flange and lower flange plate.

As discussed in Section 19.2.4.3.3 of this report and explained in Appendices 19B and 19C to DCD Tier 2, Revision 9, GEH gives details of the three-dimensional ABAQUS/ANACAP-U analysis that replaced the analysis based on empirical equations. The ABAQUS analysis verified that the drywell head shell asymmetric buckling cannot precede axisymmetric plastic yielding of the shell in the apex area. The applicant computed the Service Level C capacity of the drywell head shell and supporting components in accordance with the ASME Code, Section III. Table 19B-9 of DCD Tier 2, Revision 9, provides the results. The drywell head Level C capacity for the steady-state temperature condition of 260 degrees C (500 degrees F) is

1.033 MPaG (149.8 psig) ($3.2 P_d$), which is controlled by the capacity of the inside flange plate of the head anchor structure.

GEH provided a more realistic estimate of the failure capacity for the drywell head based on the fragility analysis. The failure state for the drywell head was defined in terms of the leakage assumed to occur because of the yielding of the anchor bolts for the bolted flanges. The HCLPF capacity at 260 degrees C (500 degrees F) for the drywell head can be estimated using information provided in DCD Tier 2, Revision 9, Table 19C-10. Given the median capacity at 1.426 MPaG (206.8 psig) and the composite uncertainty of 0.1535, the staff estimates that the HCLPF (99-percent confidence value) is 0.99 MPaG (143.6 psig) ($3.2 P_d$). The staff believes that with the yielding of the bolts for the bolted flanges being the likely failure mode for the drywell head, an uncontrolled large release through the head would not be possible.

The staff concludes that the reevaluation of the pressure capacity of the drywell head is acceptable. Therefore, RAI 19.2-40 is resolved.

The outer surface of the drywell head is immersed in a water pool which provides radiation shielding. The staff identified that the water pool is compartmentalized, is independent of the IC/PCCS cooling pools, and is periodically replenished. The water pool above the drywell head is maintained during and after a severe accident. Therefore, the water pool will limit the temperature rise across the thickness of the drywell head shell. The GEH ABAQUS analysis as provided in DCD Tier 2, Revision 4, Appendix 19B considered the presence of the water above the drywell head by requiring the temperature of the head shell to be the same as the pool water temperature, which is 43.3 degrees C (110 degrees F). The staff questioned the use of 43.3 degrees C (110 degrees F) as the temperature of the head shell and issued RAI 19.2-41 S02. In response, GEH modified the temperature under the drywell head from 43.3 degrees C (110 degrees F) to 260 degrees C (500 degrees F) and the temperature of water in the pools above the drywell head from 43.3 degrees C (110 degrees F) to 100 degrees C (212 degrees F). GEH also updated the Level C and pressure fragility analyses provided in DCD Tier 2, Revision 5. The staff considers the GEH assessment adequate and the revision included in DCD Tier 2, Revision 5, Appendix 19B acceptable. Therefore, RAI 19.2-41 is resolved.

19.2.4.3.5 Reinforced Concrete Containment

The staff reviewed the GEH analysis for estimating the internal pressure capacity of the RCCV, which is described in DCD Tier 2, Revision 9, Appendix 19B, Section 6.2.5.4.2 for Level C/factored load limits; and in Appendix B.8 to the PRA report, Revision 1, for estimating the pressure strength fragility.

GEH provided the analysis results for two loading cases in Tables 19B-6 and 19B-7 based on the detailed three-dimensional ABAQUS/ANACAP-U model. These are 0.62 MPaG (89.9 psig) and 0.992 MPaG (143.9 psig), representing the internal pressure loads induced from the most likely accident scenarios (SECY-93-087) and the 100-percent fuel clad-coolant reaction (as required by 10 CFR 50.44). Tables 19B-6 and 19B-7 in DCD Tier 2, Revision 9 compare the maximum stresses in critical areas of the RCCV to Level C allowable limits. Figure 19B-5 in DCD Tier 2, Revision 9 identifies the critical strain locations for the RCCV liner, where location A near the top of the UDW connecting to the top slab is the critical strain location. For the same location, the vertical inner rebar also showed the highest stress level (Table 19B-6), which could achieve a pressure margin of $3.17 P_d$. The liner strain at location A, however, at $2.5 P_d$, would just exceed the 0.3-percent Level C limit.

The GEH fragility analysis, as provided in DCD Tier 2, Revision 4, Appendix 19C identified a similar failure mode for the RCCV as the Level C analysis. Table 19C-8 provides a summary of the pressure fragility for the RCCV and liner. At 260 degrees C (500 degrees F) steady-state temperature, the median RCCV pressure capacity and lognormal uncertainty for liner tearing are 1.708 MPaG (247.7 psig) (5.51 P_d) and 0.1512, respectively. Therefore, the HCLPF pressure capacity for the RCCV is calculated to be 1.2 MPaG (174.0 psig) (3.877 P_d). The staff concludes that the HCLPF pressure capacity is consistent with the Level C analysis, and the higher HCLPF pressure capacity is achieved because of a realistic limit state of liner tearing strain greater than 2 percent, as opposed to the Level C limit of 0.3 percent.

On the basis of the above discussion, the staff concludes that the GEH approach is acceptable, and the analysis results of the Level C/factored loads pressure capacity and the fragility estimate for the RCCV based on the three-dimensional ABAQUS/ANACAP-U model are acceptable.

19.2.4.3.5.1 Severe Accident Temperature Loads

The staff reviewed the applicant's analysis of the severe accident temperature loads in the containment and determined that the accident temperature should be clearly defined for evaluating the containment pressure capacity and assessing the potential for thermal-induced containment liner failure.

In Appendix B.8 to the PRA report, Revision 1, GEH characterized the typical temperature of 533 K (500 degrees F) for the most likely severe accident scenarios for the ESBWR. The staff requested that GEH clarify the use of the value of 533 K (500 degrees F) for the most likely severe accident scenarios for the ESBWR. In response to this request, GEH stated that it had reviewed the accident sequences from the Level 1 PRA. GEH identified the top 10 sequences contributing to CDF and determined that the most likely (97 percent of the core damage sequences identified in the PRA) containment pressure and temperature time histories resulted from the sequence T_nDP_nIN_TSL (transient with no injection and no depressurization with release category of TSL). For this sequence, the containment pressure load at 24 hours after onset of core damage is 0.62 MPaG (89.9 psig) and the long-term pressure is below 0.70 MPaG (101.5 psig); the steady-state temperature is below 450 K (350 degrees F).

With respect to DCH events, GEH clarified during the February 5–7, 2007, onsite audit that such events are not included in the more likely containment severe accident scenarios, and their occurrence is remote and speculative. DCH is a postulated containment phenomenology event that assumes RPV failure at high pressure (greater than 1 MPaG [145 psig]). It constitutes 1 percent of the core damage sequences. The enveloping containment pressure and temperature time histories for 1 percent of the core damage sequences resulted from the sequence T_nDP_nIN_TSL, where the RPV remains at high pressure until lower head failure. In Section 8.3 of PRA, Revision 6, for this sequence, the containment pressure load at 24 hours after onset of core damage is 0.87 MPaG (124.7 psig), and the steady-state drywell temperature is below 500 K (440 degrees F). The staff finds that the pressure and temperature time-history loads used as input to the structural analysis are appropriate because the estimates of the pressure and temperature during and shortly after the vessel failure, and over the next 1 to 3 days, are consistent with the understanding of severe accident phenomenology and plant systems behavior.

Based on the above discussion, the staff concludes that the GEH assessment of severe temperature loads used as inputs to its containment performance analysis is acceptable.

19.2.4.3.5.2 Environment Loads—Seismic: Estimates of Containment Seismic Fragility

The staff reviewed and evaluated DCD Tier 2, Revisions 0 and 1, and Section 15 of the PRA report, Revision 1, with respect to the GEH SMA for Category I structures, including the reinforced concrete containment. The applicant applied the Zion method, described in NUREG/CR-2300, to the seismic HCLPF calculations and initially used the median ground response spectrum given in NUREG/CR-0098 at 0.3g PGA as the seismic demand. Subsequently, as part of a GEH supplemental RAI response and during discussions with the staff at the onsite audit from February 5–7, 2007, GEH presented a revised SMA. The revision to the SMA was necessitated by a modification GEH had made to the seismic design ground response spectrum. The new ESBWR design spectrum is specified as the envelope of RG 1.60, anchored at 0.3g PGA, and the North Anna site-specific spectrum, anchored at 0.5g PGA. To demonstrate the seismic margin of the ESBWR design, GEH presented seismic HCLPF calculations using the probabilistic variable separation approach for the critical plant SSCs for two separate seismic demand spectra: one for rock sites and one for soil sites. For rock sites, GEH used the North Anna ESP site-specific spectrum with a PGA of 0.5g. For soil sites, GEH used a spectrum anchored at 0.3g PGA that envelops the latest seismic demand spectra for all of the soil sites included in the 28 Central and Eastern United States (CEUS) sites for which EPRI has performed seismic hazard evaluation.

Consistent with SECY-93-087, the plant-level HCLPF value should be demonstrated up to approximately 1.67 times the design-basis SSE. The ESBWR design-basis SSE is defined by the response spectra shown in DCD Tier 1, Revision 9, Figures 5.1-1 and 5.1-2. The staff noted that demonstration of seismic margin using two separate response spectra does not appear to satisfy the expectation of SECY-93-087. The staff asked GEH to address two issues in the seismic margin assessment: (1) compatibility of the shape of the review-level earthquake spectrum with the design-basis spectrum and (2) selection of the review-level earthquake PGA to be about 1.67 times the design-basis PGA.

The staff finds that the seismic margin assessment based on PRA seismic sequences, as described in Section 15 of the PRA report, Revision 2, is in accord with SECY-93-087. However, the applicant estimated HCLPFs for only five structural components by analysis, while assuming that the remaining SSCs had HCLPFs equal to 0.84g PGA. Since Chapter 19 of DCD Tier 2, Revision 4, did not state that all SSCs identified on the seismic sequences will be qualified for HCLPF capacity equal to or greater than 1.67 times the ESBWR certified seismic design response spectrum (CSDRS), the staff believes that the COL applicants or licensees can qualify SSC HCLPFs with respect to the site-specific ground motion response spectrum, which is generally less than the CSDRS. RAI 19.2-92 discusses this issue further.

To address the issues raised by the staff, in DCD Tier 2, Revision 4, Chapter 19, and in Section 15 of the PRA report, Revision 2, GEH developed a performance-based seismic response spectrum (PBRs), which is the same as the CSDRS at and above 9 Hz. For frequencies below 9 Hz, the PBRs bounds all soil sites in the CEUS except Vogtle; however, it falls slightly below the CSDRS for frequencies below 9 Hz. Based on its review of the PBRs, the staff questioned why GEH did not use the CSDRS for the margin assessment. The staff believes that, consistent with SECY-93-087, CSDRS should be used for the margin assessment. The staff tracked RAI 19.2-92 as an open item in the SER with open items. In the response to RAI 19.2-92, the applicant agreed to use the ESBWR CSDRS in the seismic margin assessment and to change Table 19.2-4 of DCD Tier 2, Revision 4, accordingly. On this basis, the staff finds that the seismic margin method used for the ESBWR certified design is acceptable. The staff also agrees that the SMA has demonstrated the sequence-level HCLPF

value of $1.67 \times \text{CSDRS}$ for the ESBWR standard design, provided that the associated COL Information Item 19.2.6-1-A will be successfully confirmed. Therefore, RAI 19.2-92 and the associated open item are resolved.

The fire water service complex, which is designed and analyzed using the CSRDS, consists of two waste storage tanks, a pump enclosure, and attached piping. To ensure successful vessel water injection, all three components must remain functional during and after a seismic event. Therefore, the fault tree for the Fire Protection Water System (FPWS) should have all three components in OR-gates. In RAI 19.2-91, the staff requested that the applicant correct the FPWS fault tree and provide a revised HCLPF calculation. The staff tracked RAI 19.2-91 as an open item in the SER with open items. In response to RAI 19.2-91, GEH agreed with the staff's request. GEH modified the fault tree for the FPWS to include all three components in OR-gates. GEH also assessed the HCLPF capacity for these components to exceed $1.67 \times \text{SSE}$. The applicant revised Table 19.2-4 of DCD Tier 2, Revision 5, Chapter 19, and Section 15 of the PRA report, Revision 4, to reflect the changes made to the FPWS. The staff finds that GEH has addressed the concern adequately, and the issue is closed. Therefore, RAI 19.2-91 and the associated open item are resolved.

19.2.4.3.5.3 Containment Liner

The staff reviewed the applicant's analysis of the containment liner integrity to maintain a leaktight condition under severe accident loads. The containment liner is anchored to the reinforced concrete wall by regularly spaced T-bar stiffeners with webs welded to the liner. The T-bar stiffeners are embedded in the concrete. The T-bar stiffeners are spaced 50 cm (1.64 ft) apart. Thermal and pressure-induced liner failure should be assessed. The greatest concern is at major penetrations, where stress concentrations and constraints to thermal growth are expected.

The applicant used 21-percent ultimate fracture strain criterion for the liner material in the fragility analysis. The 21-percent strain for the liner material (SA-516, Gr. 70) is based on the material specification in ASME Code, Section III, Part A. The staff noted that 21 percent is the minimum required elongation in a 5-cm (2-in.) uniaxial test coupon, and 17 percent is the minimum required elongation in a 20-cm (8-in.) uniaxial test coupon. The liner is subject to a biaxial state of stress and strain concentrations near major penetrations. The staff concluded that the maximum liner strain should not exceed 10 percent.

To assess the liner failures induced by high-temperature loads in a DCH event, the applicant estimated the liner failure strain at 866 K (1,100 degrees F) to be about 23 percent, based on the available test data for SA-533 and A36 steel. The staff found that these tests were performed using specimens typically 5 cm (2 in.) or less, and the tests do not consider a biaxial state of stress. The staff concluded that the maximum liner strain should not exceed 11 percent (onset of void nucleation) at the DCH temperature.

In discussions with the staff during the February 5–7, 2007, onsite audit, GEH agreed to use the factored load limits of ASME Code, Section III, Division 2, for the deterministic assessment of liner integrity, and to use an 8-percent failure strain limit for the liner plate in the three-dimensional ABAQUS/ANACAP-U fragility analysis. The staff noted that in Appendices 19B and 19C to DCD Tier 2, Revision 4, GEH used ASME Code, Section III, Division 2, Subarticle CC-3720, limits for liners in the deterministic analysis and much less than 8-percent strain (Table 19C-5) in the fragility analysis. The staff finds that the applicant's approach is

acceptable, and the issues related to the ultimate fracture strain and maximum linear strain discussed above are resolved.

19.2.4.3.5.4 Penetrations

The staff reviewed the applicant's evaluation of the leakage potential of operable penetrations induced by the accident pressure and temperature. In Section B.8.2.2.2 of the PRA report, Revision 1, GEH used a SANDIA-proposed springback methodology to assess leakage prevention at seals. According to Section 8.2.1.3 of the PRA report, Revision 0, the allowable TSL is 0.5 percent of containment air volume per day at rated pressure, and based on MAAP 4.0.6 test runs, the effective flow area required to allow 0.5 percent of the containment air volume to leak per day at design pressure is approximately $3.4 \times 10^{-6} \text{ m}^2$ (3.4 square millimeters [mm^2] [$36.6 \times 10^{-6} \text{ ft}^2$]). In Section B.8.2.2.2 of the PRA report, Revision 1, GEH estimated the leakage potential for the drywell head of diameter 10.4 m (34.1 ft), with two drywell equipment hatches of diameter 2.4 m (7.87 ft), and one wetwell hatch of diameter 2.0 m (6.56 ft). According to the GEH calculation presented in Section B.8.2.2.2 of the PRA report, Revision 1, the separation displacement at 1.204 MPaG (174.6 psig) capability pressure is calculated to be about 0.146 mm (0.0057 in.) for the drywell head and 0.204 mm (0.0080 in.) for the most flexible hatch. A comparison of the separation displacements of the hatches with the springback limit (0.127 mm [0.0050 in.]) for leakage initiation, shows that the leakage gap for the drywell head is 0.019 mm (0.00075 in.) and the leakage gap for drywell hatches is 0.077 mm (0.0030 in.). Although the leakage gap of 0.019 mm (0.00075 in.) appears to be small for the drywell head, the leakage area using a 10.4-m (34.1-ft) diameter for the drywell head is estimated to be 465 mm^2 ($5.0 \times 10^{-3} \text{ ft}^2$), which is much larger than the 3.4 mm^2 ($36.6 \times 10^{-6} \text{ ft}^2$) allowed for TSL.

In discussions with the staff during the February 5–7, 2007, onsite audit, GEH stated that the three-dimensional ABAQUS/ANACAP-U analysis will be used to assess the leakage potential of major penetrations. GEH also stated that bolts for equipment hatches and the drywell head will be preloaded to ensure that there are no leakage gaps at the Level C pressure. GEH also presented the preliminary assessment results of major penetrations, which the staff finds acceptable. GEH provided the new leakage assessment of equipment hatches and the drywell head in Appendices 19B and 19C to DCD Tier 2, Revision 4, for deterministic and probabilistic analyses, respectively.

The applicant based its deterministic analysis on the ASME Code, Section III, requirements for Level C capacity determination. For the fragility analysis, GEH constructed detailed local finite element models and applied the response from the global ABAQUS model to the local models as boundary conditions. The hatch in the UDW was chosen as the basis of the modeling, since all equipment hatches have similar configurations. Furthermore, the equipment hatch in the LDW differs only in that it penetrates the thicker pedestal wall while the thinner RCCV wall in the UDW is more flexible and more critical for deformation leading to possible flange distortions or tearing in steel components of the hatch. In addition, the LDW hatch has a closure lid on the inside of the containment so that the internal pressure keeps the inner seal closed and prevents the interior of the penetration from being exposed to high temperatures. DCD Tier 2, Revision 9, Table 19C-5 provides the failure criteria (or limit states) for leakage from either tearing of steel components or flange distortion and loss of seal. The tearing is in terms of strains, while the flange separation is indicated by the first yield in bolts. The staff finds the criteria in Table 19C-5 acceptable. The fragility analysis results in DCD Tier 2, Revision 9, Table 19C-11 indicate that the pressure capacity of equipment hatches is controlled by leakage from flange distortion with a median value of 1.882 MPaG (273.0 psig) ($6.07 P_d$) at 260 degrees C.

(500 degrees F) and a composite uncertainty of 0.1542. Therefore, the HCLPF pressure capacity for equipment hatches can be inferred to be 1.315 MPaG (190.7 psig) (4.24 P_d).

The staff concludes that the assessment of leakage potential of major penetrations using the three-dimensional ABAQUS/ANACAP-U model is appropriate and acceptable. In addition, the equipment hatches appear to be rugged in resisting the internal pressure up to 4.24 P_d at an accident temperature of 260 degrees C (500 degrees F).

19.2.4.3.6 Reactor Cavity Structures

The staff reviewed the applicant's analysis of the potential failure of the reactor cavity structures subjected to postulated EVE loadings. EVE is a postulated internally initiated event of energetic FCI. It is triggered by the melt released from the failed RPV lower head falling into and traversing the depth of a preexisting water pool in the LDW cavity. EVE events result in energetic pressure pulses, with magnitudes in the kilobar range, which are potentially capable of loading major structures to failure when large quantities of melt react with highly subcooled water. The EVE loading is characterized by the impulse (the time-integral of the pressure) acting on the surface of a structure.

The BiMAC device consists of a layer of thick-walled steel pipes embedded in reinforced concrete that supports them in all directions. The RPV support brackets are made of structural steel and provide structural support to the RPV and the reactor shield wall.

19.2.4.3.6.1 Reactor Cavity—Structural Performance under Ex-Vessel Steam Explosion Loadings

The ESBWR LDW is designed with a large cavity space. The key parameter for EVE is the depth of the preexisting subcooled water pool in the LDW cavity. In the GEH PRA analysis for severe accident sequences, the reactor cavity structures and penetrations are considered to be failed when the water depth is greater than or equal to 1.5 m (4.92 ft). GEH estimated that, for those sequences in which the water level is greater than 1.5 m (4.92 ft), the contribution to core damage from sequences to be considered for the EVE constitutes only 0.9 percent of CDF. The GEH assumption of CF from EVE sequences with a water level at 1.5 m (4.92 ft) is conservative, since the closest equipment hatch in the LDW cavity is located 2.2 m (7.22 ft) above the 1.5-m (4.92-ft) critical depth of water for EVE assessment. The equipment hatch will not likely be impacted by the EVE for the subcooled water pool with a depth less than 1.5 m (4.92 ft); however, the equipment hatch is the likely CF path for a water depth greater than 1.5 m (4.92 ft). The staff noted that the design of the 2.5 m (8.2 ft) thick reactor pedestal is robust. Also, the large space of the LDW (90 cubic meters [3,178 cubic feet]) is sufficient to accommodate about 400 percent of the full-core debris. The BiMAC is covered by a 0.5 m (1.6 ft) layer of sacrificial concrete, which GEH has indicated is sufficient to protect the BiMAC from steam explosions (see MFN-10-357). Consequently, the basemat would be protected as well. For a water depth less than 1.5 m (4.92 ft), the sequences involved constitute 99 percent of CDF. GEH performed a PM-ALPHA.L-3D analysis to characterize the EVE pressure loads on the side and base of the cavity and performed a DYNA-3D analysis to quantify the structural capacity of the pedestal and BiMAC against EVE pressure impulse. In Section 21.4.4.5 of the PRA report, Revision 1, GEH estimated that the reactor pedestal pressure capacity has a margin of five times the EVE pressure loads. GEH concluded that the failure of cavity structures from EVE events is physically unreasonable. The staff finds that the pedestal and other cavity structures have a sufficient structural capacity to resist EVE pressure load and concurs with the applicant's conclusion regarding EVE-induced failure of cavity structures.

On the basis of the above discussion, the staff concludes that the GEH evaluation of the reactor cavity structures is acceptable.

19.2.4.3.6.2 *BiMAC Device—Structural Performance under Ex-Vessel Steam Explosion Loadings*

GEH assessed the effect of EVE on the functionality of the BiMAC and concluded that, for the lower water depths (less than 1.5 m [4.92 ft]), the BiMAC structural capacity is more than 8 times the pressure demand induced by the EVE event, and failure is physically unreasonable. For high water depth (more than 1.5 m [4.92 ft]), which constitutes only 0.9 percent of CDF, GEH conservatively assumed that the BiMAC failed. The staff finds the applicant's assessment of BiMAC failure from EVE events acceptable.

In response to RAI 19.2-94 through 19.2-99, GEH reduced the size of tubing for the BiMAC pipes from 10 cm (4 in.) in the original design to 5 cm (2 in.) and replaced the protective cover of 0.2 m (8 inches) Zirconia with a thicker layer of concrete (0.5 m [20 in.]). The increased thickness of the protective layer adds additional structural protection to BiMAC piping from an EVE event and, as justified by the applicant in a letter dated December 21, 2010, smaller diameter pipes would increase the capacity to withstand the collapse pressure due to an EVE event. Based on the above discussion, the staff concludes that the existing GEH analysis of the ability of the BiMAC to withstand EVE events is conservative with respect to the revised design of BiMAC, and therefore is acceptable.

19.2.4.3.6.3 *Reactor Pedestal/Vessel Supports—Structural Performance Given Failure of BiMAC and Continued Core-Concrete Interactions*

GEH confirmed that the failure of the BiMAC constitutes a breach of the containment boundary and modeled this failure in the Level 2 PRA accident progression analysis. The staff finds the GEH approach acceptable.

19.2.4.4 *Conclusion*

Section 19.2.4 of this report provides the staff's review and assessment of the applicant's evaluation of the ESBWR containment structural performance. The staff focused its review on the ability of the structural components of the containment pressure boundary to meet the (1) requirements of 10 CFR 50.44, (2) SECY-93-087 expectations for deterministic containment, and (3) SECY-93-087 expectations for seismic capacity as determined by a seismic margins assessment. The staff's review also focused on assessing the adequacy of the applicant's evaluation of containment pressure fragility.

On the basis of its review and assessment, the staff concludes that the applicant's containment performance evaluation meets the requirement of 10 CFR 50.44, the SECY-93-087 expectations for containment structural performance, and the staff's expectation of the quality of the containment pressure fragility analysis.

19.2.5 *Accident Management*

19.2.5.1 *Summary of Technical Information*

Accident management consists of the actions taken by the plant's emergency response organization (including plant operations, technical support, and management staff) to prevent

core damage, terminate core damage once it begins, maintain containment integrity, and minimize offsite radiation releases. Severe accident management refers to those actions that would mitigate the consequences of accidents that result in core damage. The objectives of a severe accident management program are to arrest core melt progression by cooling the molten core material, either in-vessel, if possible, or ex-vessel if the debris has entered the containment building, and to ensure that fission products are not released to the environment. The ultimate objective is to achieve a safe, stable state. To accomplish these objectives, the emergency response organization should make full use of the plant's design features, including both standard and nonstandard use of plant systems and equipment.

The nuclear power industry initiated a coordinated program on accident management in 1990 (Section 5 of NEI 91-04, Revision 1, "Severe Accident Closure Guidelines," lays out the elements of the industry's severe accident management closure actions that have been accepted by the NRC). This program involves the development of (1) a structured method by which utilities may systematically evaluate and enhance their abilities to deal with potential severe accidents, (2) vendor-specific accident management guidelines for use by individual utilities in establishing plant-specific accident management procedures and guidance, and (3) guidance and material to support utility activities related to training in severe accidents. Using the guidance developed through this program, each operating plant has implemented a plant-specific accident management plan as part of an industry initiative.

Based on its reviews of these efforts, severe accident evaluations in IPEs, and industry PRAs, the staff has concluded that improvements to utility accident management capabilities could further reduce the risk associated with severe accidents. Although future reactor designs such as the ESBWR will have enhanced capabilities for the prevention and mitigation of severe accidents, accident management will remain an important element of defense-in-depth for these designs. However, the increased attention to accident prevention and mitigation in these designs can be expected to alter the scope and focus of accident management relative to that for operating reactors. For example, increased attention to accident prevention and the development of error-tolerant designs can be expected to decrease the need for operator intervention, while increasing the time available for such action if necessary. This will tend to reduce the need for the emergency response organization to make rapid decisions and will permit a greater reliance on support from outside sources. For longer times (several hours to several days) after an accident, the need for human intervention and accident management will continue.

For both operating and advanced reactors, the overall responsibility for accident management, including development, implementation, and maintenance of the accident management plan, lies with the nuclear utility, because the utility bears ultimate responsibility for the safety of the plant and for establishing and maintaining an emergency response organization capable of effectively responding to potential accident situations. For operating plants, vendors have played key roles in providing essential severe accident management guidance and strategies for implementation. This guidance has served as the basis for severe accident management procedures and for training utility personnel in carrying out the procedures. Computational aids for technical support have been developed, information needed to respond to a spectrum of severe accidents has been provided, decision-making responsibilities have been delineated, and utility self-evaluation methodologies have been developed and utilized.

19.2.5.2 Staff Evaluation

In RAI 19.2.4-1 and its supplements, the staff requested additional information on the technical basis for severe accident management in the ESBWR and on the process that GEH will use to develop the severe accident guidelines (SAGs). In response to RAI 19.2.4-1 S02, GEH provided additional details regarding development of the SAGs and referred to NEDO-33274, Revision 2, "ESBWR Human Factors Engineering Procedures Development Implementation Plan," issued March 2007, which presents the processes and methodologies to be used in the development of procedures including ESBWR SAGs and the ESBWR SAMGs derived from them. The staff tracked RAI 19.2.4-1 as an open item in the SER with open items. GEH provided additional details in response to RAI 19.2.4-1 S03. The staff reviewed the response, which includes suggested changes to the containment flooding severe accident guideline currently in place to be followed by BWR Owners Group (BWROG) members, and is satisfied that it will enhance the technical basis supporting the existing BWROG accident management procedures. Therefore, RAI 19.2.4-1 and the associated open item are resolved.

19.2.5.3 Conclusion

The staff finds the process that the applicant proposes to use for the development of SAGs to be consistent with the process used by currently operating BWRs and, therefore, is adequate.

19.2.6 Consideration of Potential Design Improvements under 10 CFR 50.34(f)

19.2.6.1 Regulatory Criteria

In 10 CFR 52.47(b)(2), the NRC requires applicants for standard design certification to include an environmental report required by 10 CFR 51.55. Regulation 10 CFR 51.55(a) requires the design certification applicant to "address the cost and benefit of severe accident mitigation design alternatives (SAMDA), and the bases for not incorporating SAMDAs in the design to be certified."

In 10 CFR 50.34(f)(1)(i), the NRC requires an applicant to "perform a plant/site specific PRA, the aim of which is to seek such improvements in the reliability of core and CHR systems as are significant and practical and do not impact excessively on the plant." The applicant provided an initial evaluation of potential design improvements SAMDAs for the ESBWR in response to RAI 19.4-1.

To address questions raised by the staff on the initial evaluation, GEH provided a revised RAI response (RAI 19.4-1 S03). In this response, the applicant concluded that, because of the small risk associated with the ESBWR design, a majority of the design improvements beyond those that already exist as part of the design were either of a procedural and administrative nature or were not considered to be cost beneficial. The review of the applicant's evaluation is presented below.

The staff followed applicable guidance from SRP Section 19.0, Revision 2 in performing its analysis.

19.2.6.2 Summary of Technical Information

19.2.6.2.1 Estimate of Risk for the ESBWR

As stated in Section 19.1.4.3 of this report, the applicant provided an estimate of the offsite risk to the population within 0-1.6 and 0-16 km (0-1 and 0-10 miles) of the generic ESBWR site in Section 10 of Revision 6 of the PRA report,. Table 19.1-10 of this report summarizes the baseline results for internal and external events occurring during full-power operation and shutdown conditions, and compares them to the NRC's individual and societal safety goals. The results indicate that the risk from severe accidents would be at least two to three orders of magnitude lower than the NRC's safety goals.

For external events and shutdown modes, the PRA includes values for all but seismic events. The PRA report, Revision 6 lists the external event and shutdown CDF and LRF results. The values listed show the same magnitude as those for the at-power internal events case. Because the individual CDF values are developed with differing levels of conservatism, the applicant indicated that it is not meaningful to add the CDF or LRF values to create total values. Nevertheless, it is apparent that, for the two safety goal measures, the total risk from all accidents (internal and external events) would not increase by more than two orders of magnitude.

GEH affirms that the individual risk and societal risk goals are maintained with sufficient margin. The risk results, together with supporting sensitivity studies, lead to the risk insight that the public health and safety are well protected in the ESBWR design, as shown by the PRA analysis.

19.2.6.2.2 Identification of Potential Design Improvements

In NEDO-33306, Revision 4, "ESBWR Severe Accident Mitigation Design Alternatives," the applicant identified 177 candidate design alternatives based on a review of design alternatives for other plant designs, including the license renewal environmental reports and the GEH ABWR SAMDA study. The applicant eliminated certain design improvements from further consideration on the basis that the ESBWR design already incorporates them. The following are examples of design enhancement features currently included in the design:

- Improved IC design
- Automatic DPVs
- AC-independent fire water pumps for makeup and injection
- PCCS
- BiMAC device and GDCS deluge function
- Improved dc power reliability
- Improved actuation logic reliability
- Motor-driven feedwater pumps
- Water pool above drywell head
- Containment ultimate strength and maximum design pressure
- Incorporation of flood mitigation into design
- RWCU heat exchanger sized for DHR
- 72-hour coping period for SBO
- Upgraded low-pressure piping for the RCPB
- Digital I&C

The applicant's screening process eliminated 40 potential alternatives as being inapplicable, 71 design alternatives considered to be similar to those already included in the ESBWR design, 27 items marked as procedural or administrative as opposed to design features (whose benefits were considered to be unlikely to exceed those of alternatives evaluated relative to their potentially high costs), and 37 items were ruled out for cases where other design features already perform the proposed function or obviate its need. The applicant assessed the remaining two items and found them to have very low benefit because their insignificant contribution to reducing risk did not outweigh their excessive implementation costs.

19.2.6.2.3 Risk Reduction Potential of Design Improvements

The applicant assumed that each design alternative would work perfectly to completely eliminate all severe accident risk from evaluated internal events. This assumption is conservative as it maximizes the benefit of each design alternative. In the PRA Report, the applicant reported results from the ESBWR Level 3 PRA, namely, an annual offsite population dose risk (W_{pha}) of 0.035 sievert per year and a maximum averted public exposure cost of \$194,740. The applicant estimated the public exposure design alternative benefits on the basis of the reduction of risk expressed in terms of whole-body person-rem per year received by the total population within an 80-km (50-mi) radius of the ESBWR plant site.

The applicant used the cost-benefit methodology found in NUREG/BR-0184, "Regulatory Analysis Technical Evaluation Handbook," issued in January 1997, to calculate the maximum attainable benefit associated with completely eliminating all risk for the ESBWR. This methodology considers averted onsite and replacement power costs. The applicant estimated the present worth of eliminating all severe accident risk to be about \$397,863

The applicant's risk reduction estimates are based on point-estimate (mean) values, without consideration of uncertainties in CDF or offsite consequences. Even though this approach is consistent with that used in previous design alternative evaluations, further consideration of these factors could lead to significantly higher risk reduction values, given the extremely small CDF and risk estimates in the baseline PRA. In assessing the risk reduction potential of design improvements for the ESBWR, the staff has based its evaluation on the applicant's risk reduction estimates for the various design alternatives, in conjunction with an assessment of the potential impact of uncertainties on the results. Section 19.2.6.3 of this report discusses this assessment further.

19.2.6.2.4 Cost Impacts of Candidate Design Improvements

NEDO-33306 assessed the capital cost associated with two design alternatives evaluated by the applicant for the ESBWR. For both design alternatives, the implementation cost would be over \$1 million, which is much greater than the maximum averted benefit, making any additional design modifications costly as compared to any potential benefits.

On the basis of the analyses performed by GEH, the staff views the applicant's assertion of potential costs for the ESBWR as acceptable because it is reasonable to conclude that the cost of implementing (design, procurement, installation, testing, etc.) the design alternatives that were considered, such as constructing a building connected to the containment building or installing limit switches on all containment isolation valves, would far exceed GEH's \$1 million minimum cost estimate.

19.2.6.2.5 Cost-Benefit Comparison

The methodology used by GEH was based primarily on the NRC's guidance for performing cost-benefit analysis outlined in NUREG/BR-0184. The guidance involves determining the net value for each SAMDA according to the following formula:

$$\text{Net Value} = (\text{APE} + \text{AOC} + \text{AOE} + \text{AOSC}) - \text{COE}$$

where:

APE = present value of averted public exposure (\$)

AOC = present value of averted offsite property damage costs (\$)

AOE = present value of averted occupational exposure costs (\$)

AOSC = present value of averted onsite costs (\$) (This includes cleanup and decontamination and long-term replacement power costs.)

COE = cost of enhancement (\$)

If the net value of a SAMDA is negative, the cost of implementing the SAMDA is larger than the benefit associated with the SAMDA, and it is not considered to be cost beneficial. Table 19.2-2 summarizes the applicant's and staff's estimates of each of the associated cost elements. The NRC issued NUREG/BR-0058, Revision 4, "Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission," in August 2004, to reflect the agency's policy on discount rates. Revision 4 states that two sets of estimates should be developed—one at 3 percent and one at 7 percent. The applicant provided estimates using a 3-percent discount rate, since it represented a more conservative estimate.

It is important to note that the monetary present value estimate for each risk attribute does not represent the expected reduction in risk resulting from a single accident. Rather, it is the present value of a stream of potential losses extending over the projected lifetime (in this case, 60 years) of the facility. Therefore, it reflects the expected annual loss resulting from a single accident, the possibility that such an accident could occur at any time over the licensed life, and the effect of discounting these potential future losses to present value.

As indicated above, the applicant estimated the total present dollar value equivalent associated with complete elimination of severe accidents at a single ESBWR unit site to be \$397,863. The estimated averted health exposure has the largest effect on the averted cost. For any SAMDA to be cost beneficial, the enhancement cost must be less than \$397,863. Based on this, the applicant concluded that none of the SAMDA candidates are cost beneficial.

Table 19.2-2. Summary of Estimated Averted Costs.

QUANTITATIVE ATTRIBUTES		PRESENT VALUE ESTIMATE (\$)		
		NRC BEST ESTIMATE ^a	GEH MAXIMUM ^b	NRC MAXIMUM ^c
Health	Public	100,000 ^d	194,740	197,720
	Occupational	56	249	250
Property	Offsite	27,200 ^d	53,720 ^d	53,770 ^d
	Onsite	NA ^e	NA ^e	NA ^e
Cleanup and Decontamination	Onsite	1,710	4,674	4,060
Replacement Power		4,520	144,480	148,020
Total		133,486	397,863	403,820

- "Best estimate" is based on mean release frequency (from Revision 6 of the PRA report), "best estimate" parameter values in NUREG/BR-184, and 3-percent discount rate.
- Maximum estimate is based on mean release frequency, high estimate parameter values in NUREG/BR-0184, and a 3-percent discount rate.
- NRC staff maximum is based on parameter values used in b, release frequency (from Revision 6 of the PRA report), and a 3-percent discount rate.
- Estimated using the applicant-provided EPRI ALWR URD, property damage, and the new release category frequencies.
- This value was not analyzed.

19.2.6.3 Staff Evaluation

In 10 CFR 50.34(f)(1)(i), the NRC requires an applicant to perform a plant- or site-specific PRA. The aim of this PRA is to seek improvements in the reliability of core and CHR systems that are significant and practical and do not have an excessive impact on the plant. On the basis of its review, the staff concludes that the ESBWR PRA and the applicant's use of the insights of this study to improve the design of the ESBWR meet this requirement.

The set of potential design improvements considered for the ESBWR includes those from generic BWR severe accident mitigation alternatives reports and from the ABWR design. The ESBWR design already incorporates several design enhancements related to severe accident mitigation. These design improvements have resulted in a CDF that is about one order of magnitude less than that of the ABWR design. For example, the ESBWR design can cope with an SBO for 72 hours (i.e., no reliance on ac power for the first 72 hours), eliminating CDF sequences that contributed more than 40 percent of CDF in the ABWR design.

The staff considers the applicant's review of the potential SAMDAs and their impacts on the ESBWR design acceptable. The staff's review did not reveal any additional design alternatives that the applicant should have considered.

The applicant's estimates of risk do not account for uncertainties either in CDF or in offsite radiation exposures resulting from a core damage event. The uncertainties in both of these key

elements are fairly large because key safety features of the ESBWR design are unique, and with the features already incorporated in the ESBWR design, the ability to estimate CDF and risk approaches the limitations of probabilistic techniques. In view of the limits of PRA techniques, and because site-specific factors do not affect the uncertainties in CDF values and CDF is very low on an absolute scale as compared to currently operating plants, further evaluation of such uncertainties is not warranted.

For external events, GEH's analysis only includes high winds; however, the contribution to the CDF from external events not yet accounted for in the SAMDA analysis is not expected to cause a SAMDA item that has previously been considered to become cost beneficial. While external events and accident sequences not yet accounted for in the SAMDA analysis may increase the total CDF in the plant-specific PRAs, the CDF for the design is very low, and the costs and benefits of SAMDAs that relate to the risk from external events are comparable to those of the SAMDAs that relate to the risk from internal events. Any increase in CDF in a plant-specific PRA is not expected to alter these facts. Accordingly, and in view of the features already incorporated in the ESBWR design and the margin between the cost of SAMDAs evaluated and their potential benefits, as described below, SAMDAs that relate to the risk from external events are not cost-beneficial now, and are not likely to become cost beneficial based on a plant-specific PRA.

The staff's analyses of the total present value using the mean CDF and release frequencies from Revision 6 of the PRA report and a 3-percent discount rate indicate a maximum value of about \$403,820. This compares well to the GEH estimate of the maximum benefit from the elimination of all CDF of \$397,863. Accordingly, the staff concludes that the GEH estimate of maximum benefit from any SAMDA and the use of only the 3-percent discount rate are reasonable.

The estimated averted health exposure is a major contributor to the estimated benefits. This arises from relatively high release frequencies for internal and high-wind events during shutdown. The high releases are assumed because the containment would be open during most of the shutdown period. Additionally, if one were to adjust annual replacement power cost for future energy cost increases, the total present dollar value would be even higher. Nonetheless, CDF is very low on an absolute scale as compared to currently operating plants. Moreover, in view of the features already incorporated in the ESBWR design and the margin between the cost of SAMDAs evaluated and their potential benefits, any increase in benefits due to increased replacement power costs would not be significant enough to render any SAMDAs evaluated in this report cost-beneficial. Therefore, further evaluation of future energy cost increases is not warranted.

19.2.6.4 Conclusion

GEH indicated that any design modifications would cost approximately a minimum of \$1 million to implement, as indicated above. As described in Section 19.2.6.2.4 of this report, the staff concluded that the GEH estimate of \$1 million per modification is conservative. The minimum cost of \$1 million is approximately 2.5 times the maximum benefit of \$397,863 (calculated by the applicant), and therefore the NRC staff concurs with the applicant's conclusion that none of the potential design modifications evaluated could be justified on the basis of cost-benefit considerations. The staff further concludes that it is unlikely that any other design changes would be justified on the basis of person-rem exposure considerations because the estimated CDF would remain very low on an absolute scale.

Based on the applicant's response, RAI 19.4-1 is resolved.

19.2.7 Design Features for Protection against a Large, Commercial Aircraft Impact

This section describes the staff's evaluation of the description of design features and functional capabilities credited by the applicant to show that the facility can withstand the effects of a large, commercial aircraft impact. These design features and functional capabilities are described in DCD Tier 2, Revision 9, Appendix 19D.

The impact of a large, commercial aircraft is a beyond-design-basis event. Under 10 CFR 50.150, applicants for new nuclear power reactors⁴ are required to perform an assessment of the effects on the designed facility of the impact of a large, commercial aircraft. Applicants are required to submit a description of the design features and functional capabilities identified as a result of the assessment (key design features) in their DCD together with a description of how the identified design features and functional capabilities show that the acceptance criteria in 10 CFR 50.150(a)(1) are met. Applicants subject to 10 CFR 50.150 must make the complete aircraft impact assessment available for NRC inspection, at the applicants' offices or their contractors' offices, upon NRC request in accordance with 10 CFR 50.70, 10 CFR 50.71, and Section 161.c of the Atomic Energy Act of 1954, as amended.

19.2.7.1 Regulatory Criteria

NUREG-0800 was not used to perform this review because it does not address large, commercial aircraft impact analysis requirements. The staff used the following relevant regulations and guidance to perform this review.

19.2.7.1.1 Applicable Regulations

- 10 CFR 50.150(a)(1) requires that applicants perform a design specific assessment of the effects on the facility of the impact of a large, commercial aircraft. Using realistic analyses, the applicant shall identify and incorporate into the design those design features and functional capabilities to show that, with reduced use of operator actions: (i) The reactor core remains cooled, or the containment remains intact; and (ii) spent fuel cooling or SFP integrity is maintained.
- 10 CFR 50.150(b) requires that the final safety analysis report include a description of: (1) the design features and functional capabilities which the applicant has identified for inclusion in the design to show that the facility can withstand the effects of a large, commercial aircraft impact in accordance with 10 CFR 50.150(a)(1); and (2) how those design features and functional capabilities meet the assessment requirements of 10 CFR 50.150(a)(1).

19.2.7.1.2 Review Guidance

- Draft Guide (DG) 1176 "Guidance for the Assessment of Beyond-Design-Basis Aircraft Impacts," issued July 2009, provides guidance for meeting the requirements in 10 CFR 50.150(a), and specifically, documents NRC endorsement of the methodologies described in the industry guidance document, Nuclear Energy Institute (NEI) 07-13,

⁴ "Applicants for new nuclear power reactors" is defined in the Statement of Considerations for the Aircraft Impact Rule [74 FR 28112, June 12, 2009].

“Methodology for Performing Aircraft Impact Assessments for New Plant Designs,” Revision 7, issued May 2009.

- Statements of Consideration for the aircraft impact assessment rule [74 FR 28112, June 12, 2009] which indicate, among other things, that for the NRC to conclude that the rule has been met, it must find that the applicant has performed an aircraft impact assessment reasonably formulated to identify design features and functional capabilities to show, with reduced use of operator action, that the acceptance criteria in 10 CFR 50.150(a)(1) are met.
- The following staff interim review guidelines:

(a) Reasonably Formulated Assessment Guideline

The NRC considers an aircraft impact assessment performed by qualified personnel using a method that conforms to the guidance in NEI 07-13, Revision 7 to be a method which is reasonably formulated. The NRC considers qualified personnel to be: (1) an applicant who is the designer of the facility for which the aircraft impact assessment applies; and (2) an applicant’s primary contractor for the aircraft impact assessment who has designed a nuclear power reactor facility either already licensed or certified by the NRC or currently under review by the NRC.

(b) Reactor Core and Spent Fuel Pool Cooling Design Features Guideline

The “reactor core cooling” criterion or “spent fuel pool cooling” criterion in 10 CFR 50.150(a)(1) is satisfied if design features have been included in the design of the plant to specifically perform that cooling function with reduced use of operator action.

(c) Intact Containment Guideline

The “intact containment” criterion in 10 CFR 50.150(a)(1) is satisfied if the containment: (1) will not be perforated by the impact of a large, commercial aircraft; and (2) will maintain ultimate pressure capability, given a core damage event until effective mitigation strategies can be implemented. Effective mitigation strategies are those that provide, for an indefinite period of time, sufficient cooling to the damaged core or containment to limit temperature and pressure challenges below the ultimate pressure capability of the containment as defined in the DCD Tier 2, Revision 9, Chapter 19.

(d) Spent Fuel Pool Integrity Guideline

The “spent fuel pool integrity” criterion in 10 CFR 50.150(a)(1) is satisfied if the impact of a large, commercial aircraft on the SFP wall or support structures would not result in leakage through the SFP liner below the required minimum water level of the pool.

(e) Reduced Operator Action Guideline

The NRC considers use of operator action to be reduced when: (1) all necessary actions to control the nuclear facility can be performed in the control room or at an alternate station containing equipment specifically designed for control purposes; and (2) a reduced amount of active operator intervention, if any, is required to meet the acceptance criteria in 10 CFR 50.150(a)(1). Reduction in the use of operator action is measured relative to the actions required to address aircraft impact without the aircraft impact assessment rule in place (e.g., similar actions contained in operational programs in place at current operating reactor sites).

19.2.7.2 Summary of Technical Information

In DCD Tier 2, Revision 9, Appendix 19D, the applicant states that they performed an aircraft impact assessment in accordance with the requirements in 10 CFR 50.150(a)(1) using the methodology described in NEI 07-13, "Methodology for Performing Aircraft Impact Assessments for New Plant Designs," Revision 7, as endorsed by the NRC in DG-1176. Based on the results of the assessment, the applicant has identified a set of key design features to show that the acceptance criteria in 10 CFR 50.150(a)(1) are satisfied. These key design features are reported in DCD Tier 2, Revision 9, Appendix 19D, along with references to other sections of the DCD that provide additional detail. DCD Tier 2, Revision 9, Appendix 19D also contains descriptions of how the key design features show that the acceptance criteria in 10 CFR 50.150(a)(1) are met.

19.2.7.2.1 Description of Key Design Features

The credited design features, their function(s), and references to sections containing the detailed descriptions are summarized below:

- The ICS, as described in DCD Tier 2, Revision 9, Section 5.4.6 provides core cooling.
- The ECCS, as described in DCD Tier 2, Revision 9, Section 6.3 provide core cooling.
- The main steam isolation system (MSIS), as described in DCD Tier 2, Revision 9, Section 5.4.5 maintains high pressure for core cooling with the ICS.
- The CRDS, as described in DCD Tier 2, Revision 9, Section 4.6 inserts control rods to shutdown the reactor. This enables core cooling with the systems described above.
- The Q-DCIS, as described in DCD Tier 2, Revision 9, Section 7.1 actuates the CRDS to shutdown the reactor and enable core cooling and initiates ADS and GDCS for core cooling at low pressure.
- The RCCV, as described in DCD Tier 2, Revision 9, Sections 3.8 and 6.2 protects key design features located inside the RCCV from structural and fire damage.
- The location and design of the RB structure, including exterior walls, interior walls, intervening structures inside the building and barriers on large openings in the exterior walls, as described in DCD Tier 2, Revision 9, Section 3.8 protects the RCCV from impact by a large, commercial aircraft.
- The location and design of the TB structure, as described in DCD Tier 2, Revision 9, Section 3.8 protect the adjacent wall of the RB from impact by a large commercial, aircraft.
- The location and design of the FB structure, as described in DCD Tier 2, Revision 9, Section 3.8 protect the adjacent wall of the RB from impact by a large, commercial aircraft.
- The location and design of fire barriers inside the RB, as described in DCD Tier 2, Revision 9, Section 9.5.1, and Appendices 9A and 19D protect credited core cooling equipment from fire damage.

- The location (below grade) and design of SFP structure, as described in DCD Tier 2, Revision 9, Section 1.2, Figures 1.2-1 to 1.2-20 protect the SFP from impact by a large, commercial aircraft.

19.2.7.2.2 Description of How Regulatory Acceptance Criteria are Met

The acceptance criteria in 10 CFR 50.150(a)(1) are: (1) the reactor core will remain cooled or the containment will remain intact; and (2) SFP cooling or SFP integrity is maintained. The applicant has met 10 CFR 50.150(a)(1) by including features in the ESBWR design that maintain core cooling and SFP integrity following the impact of a large, commercial aircraft.

As indicated in DCD Tier 2, Revision 9, Appendix 19D, the applicant proposes to maintain core cooling using the safety-related systems described in DCD Tier 2, Revision 9, Appendix 19D which have been designed specifically to ensure that the reactor can be shutdown and decay heat can be removed adequately from the reactor core. Some of this equipment is located inside the RCCV and some is located inside the RB. Locations inside the RCCV are protected from structural, shock and fire damage by the design of the RCCV structure as well as the RB structure which limits the penetration of a large, commercial aircraft such that the RCCV is not perforated. Equipment inside the RB is protected by structural design features of the RB itself and by structures adjacent to the RB, including the TB and the FB. In addition, fire barriers have been designed and located in the RB to contain the spread of fire inside the building such that at least one train of safety-related equipment for core cooling is protected for each RB impact scenario.

The ESBWR satisfies the SFP integrity acceptance criterion in 10 CFR 50.150(a)(1) due to the location of the SFP. The SFP structure is located below ground which protects the structure from impact by a large, commercial aircraft.

19.2.7.3 Staff Evaluation

The staff has reviewed the description of key design features provided by the applicant and the description of how the key design features show that the acceptance criteria in 10 CFR 50.150(a)(1) are met. The staff's evaluation is provided below.

19.2.7.3.1 Reasonably Formulated Assessment

The applicant states in DCD Tier 2, Revision 9, Appendix 19D that their aircraft impact assessment is based on the guidance of NEI 07-13, Revision 7. Based on the applicant's use of NRC endorsed guidance document NEI 07-13, Revision 7, the staff finds that the applicant has performed a reasonably formulated assessment.

19.2.7.3.2 Key Design Features for Core Cooling

The key design features listed in DCD Tier 2, Revision 9, Appendix 19D that perform a core cooling related function are all safety-related design features that have been designed specifically to perform the core cooling functions during normal power operation and following design-basis events initiated during power operation. The staff has considered the descriptions of the features, as well as staff reviews documented in other sections of this report of the ability of these features to perform their design basis safety functions, in order to confirm that they are suitable for maintaining core cooling following impact of a large, commercial aircraft. During its review, the staff confirmed that all of these design features can be initiated and operated from

the control room and require little, if any, further operator intervention to maintain the core cooling function.

In its initial review of the descriptions provided by the applicant, the staff noted that the applicant did not include a description of design features nor functional capabilities relied upon to ensure that the acceptance criteria in 10 CFR 50.150(a)(1) are met while the plant is shutdown and the reactor core is being cooled via the SDC system. In RAI 19.5-15 the staff requested that the applicant: (1) describe those design features and/or functional capabilities relied upon to ensure that the acceptance criteria in 10 CFR 50.150(a)(1) are met while the plant is shutdown and the reactor core is being cooled via the SDC system; (2) describe how these design features and/or functional capabilities meet the acceptance criteria in 10 CFR 50.150(a)(1); and (3) modify DCD Tier 2, Appendix 19D, to include these descriptions. In its response, the applicant proposed a modification to DCD Tier 2, Appendix 19D, which states that when normal cooling systems are not available following impact of a large, commercial aircraft, the ICS serves as a key design feature for core cooling when the plant is shutdown and the reactor is in Mode 5 and the GDSCS serves that function when the reactor is in Mode 6. The staff has evaluated use of the ICS and GDSCS to provide core cooling in these modes in Section 19.1.6 of this report and finds it to be acceptable. The staff accepts the applicant's revision of DCD Tier 2, Revision 8, Appendix 19D. Therefore, RAI 19.5-15 is resolved.

During its initial review of the ICS description, the staff noted that the pools of water used for cooling the IC condensers are not identified as part of the ICS. In RAI 19.5-20 the staff requested that the applicant state whether or not the isolation condenser/passive containment cooling system (IC/PCCS) water pools were considered key design features, since these pools are needed for the ICS to successfully remove decay heat from the core. In their response the applicant stated that these pools were considered key design features and proposed a modification to DCD Tier 2, Revision 8, Appendix 19D, which includes a statement that the IC/PCCS pools are key design features. The staff accepts the applicant's modification to DCD Tier 2, Revision 8, Appendix 19D. Based on the applicant's response, RAI 19.5-20 is resolved.

The staff noted during its initial review of the ICS description, that the ICS in combination with the IC/PCCS pools is designed to remove decay heat for a period of 72 hours following a design basis event without operator intervention to refill the pools. In RAI 19.5-21, the staff asked the applicant to clarify whether or not the IC and its heat sink were capable of ensuring core cooling following a beyond-design-basis large, commercial aircraft impact event until measures for long term cooling could be established. In response, the applicant stated that the inventory of water available in the IC/PCCS pools following a beyond-design-basis aircraft impact event had been calculated for beyond-design-basis event conditions and is sufficient to allow measures for long term cooling to be established. The staff finds the applicant's response acceptable. Therefore, RAI 19.5-21 is resolved.

19.2.7.3.3 Key Design Features that Protect Core Cooling Design Features

19.2.7.3.3.1 *Fire Protection*

The fire protection key design features that protect core cooling key design features include specific fire-rated barriers located within the RB as identified in DCD Tier 2, Revision 9, Table 19D-1, and described in Section 9.5.1, Appendix 9A, Appendix 19D, and Figures 9A.2-1 through 9A.2-11. The applicant states the design and locations of the credited fire barriers confine the spread of fire damage resulting from a large, commercial aircraft impact. Specifically, the

applicant states the fire damage is adequately confined such that at least one division of safety-related equipment and controls remains available for core cooling.

The staff noted during its initial review of the key design features descriptions provided by the applicant that a clarification was required concerning locations of the credited fire protection features. In RAI 19.5-18 the staff requested that the applicant clarify if there were any fire protection-related key design features in the FB and CB. In their response and modification to DCD Tier 2, Revision 6, Appendix 19D, the applicant states there are no fire protection related key design features within the FB, CB or any other site building. The staff finds this response acceptable because the fire protection key design features only need to protect the credited core cooling design features. Based on the applicant's response, RAI 19.5-18 is resolved.

The staff also noted during its initial review of the key design features descriptions provided by the applicant, that DCD Tier 2, Appendix 19D did not contain adequate identifications or descriptions of the fire barrier walls and fire doors within the RB. In RAI 19.5-19 the staff requested that the applicant provide the overpressure capabilities for each fire door (i.e., rated for 34.5 kPa differential pressure [kPaD] [5 pounds per square inch differential pressure [psid]] - or regular fire door) that is a key design feature. The staff found the applicant's response inadequate as it did not provide the overpressure capability of each fire door, individually, nor include all the credited fire protection key design features. The applicant's revised response clarifies that all fire barriers between the east side (safety divisions 1 and 2) and the west side (safety divisions 3 and 4) are to be credited key design features. The response included an addition of Table 19D-1 to DCD Tier 2, Revision 6, Appendix 19D that lists each credited fire door required to be rated for at least 34.5 kPaD (5 psid). The applicant also identified additional key design features such as the fire doors throughout the RB stairways, the refueling floor (elevation 34,000 mm [111.5 ft]), and credits the location of the RB HVAC system in the modification to DCD Tier 2, Revision 6, Appendix 19D. The applicant states that the stairway doors and refueling floor (elevation 34,000 mm [111.5 ft]) protect the required core cooling equipment, located below the refueling floor, from the spread of a fire caused by a large, commercial aircraft impacting the refueling floor. In addition, the applicant states RB HVAC trains do not penetrate the walls separating the east and west sides of the RB thus eliminating any penetrations and flow paths for the fire damage to spread to either the east side or west side of the RB. The staff finds this response acceptable because the applicant has identified the credited fire protection key design features and the applicant's description of these features includes enough information to be adequate. Based on the applicant's response, RAI 19.5-19 is resolved.

The staff noted that during the review of DCD Tier 2, Revision 8, the applicant included additional changes in Appendices 19D and 9A. The changes in Appendix 19D include the crediting of fire barriers as a whole and removing the East-West separation credit, which originally credited that at least two divisions will remain free of fire damage. In the revised Appendix 19D, the applicant credits at least one quadrant to remain free of fire damage. Appendix 9A and Table 19D-1 were modified to reflect additional fire barriers and fire doors required to protect at least one quadrant of credited core cooling equipment. The staff finds this change acceptable because the change still meets the guidance provisions and the descriptions of key design features remain adequate. Additional changes in Appendix 19D include modifications to meet the staff's stated position that fire barriers as a whole should be credited as opposed to just fire doors. Table 19D-1 was modified to credit fire barriers and remove applicable references to fire doors. The applicant clarifies that fire barriers includes fire doors, walls, and penetration seals. The staff notes that Table 19D-1 maintains the necessary pressure ratings for each component. The staff finds this change acceptable because the

applicant maintains an adequate description of the key design features and includes the entire fire barrier as required by the staff's position on the NEI 07-13 fire spread rule set.

The staff noted that during the review of DCD Tier 2, Revision 9, the applicant included additional changes in Appendices 19D and 9A. These changes include: crediting of at least one division of safety-related equipment in the RB instead of one quadrant; the crediting and application of 5-psid capabilities to the commodity chases within each RB quadrant; and the addition of a horizontal 5-psid, fire rated barrier within two commodity chases to separate the refueling floor from the lower elevations. The staff recognizes and accepts that the applicant has identified additional key design features believed to be necessary to maintain one division of credited equipment free of fire damage. The staff also recognizes and accepts that only one division of core cooling equipment is necessary to maintain core cooling, because each division contains 100-percent core cooling capability. In addition, the Aircraft Impact Assessment rule does not require accommodation for single failure or systems assumed to be taken out of service for maintenance.

Based in the above, the staff finds the applicant's description of the fire protection key design features for maintaining core cooling to be adequate.

19.2.7.3.3.2 Reinforced Concrete Containment Vessel Structure

In DCD Tier 2, Revision 9, Appendix 19D, the applicant states that the RCCV is a key design feature that would provide physical protection to the safety systems located inside the RCCV. The staff reviewed DCD Tier 2, Revision 9, general arrangement drawings (Figures 1.1-1, 1.2-1 through 1.2-20) and Section 3.8 information. The applicant states that the RCCV is entirely surrounded by the RB structure and, therefore, a direct impact on the RCCV of a large, commercial aircraft is not possible. Based on its review, the staff finds the applicant's description of the RCCV as a key design feature for protecting safety systems inside the RCCV to maintain core cooling to be adequate.

19.2.7.3.3.3 Reactor Building Structure

In DCD Tier 2, Revision 6, Appendix 19D, the applicant states that the location and design of the RB structure are key design features that protect the RCCV from the impact of a large, commercial aircraft. The staff reviewed DCD Tier 2, Revision 6, general arrangement drawings (Figures 1.1-1, 1.2-1 through 1.2-20) and Section 3.8 information. During review of this information, the staff noted that there were openings on the RB refueling floor that could be subjected to secondary impacts (e.g., debris) from a large, commercial aircraft impact. To address this concern, the staff issued RAI 19.5-17 in which the applicant was requested to state whether secondary impacts were considered in the assessment of structural damage to the refueling floor. The applicant responded to the staff's request by stating the analysis of aircraft impacts to the refueling floor considers openings that may be subjected to secondary impacts. Further, the applicant stated that acceptance criteria listed in DCD Tier 2, Revision 6, Appendix 19D (from 10 CFR 50.150(a)(1)), are met and that the DCD Tier 2, Revision 6, Appendix 19D would be revised to provide additional information relative to secondary impacts. Based on the applicant's RAI response and DCD revision, RAI 19.5-17 is resolved.

The staff noted during its initial review of the ICS description that the IC/PCCS pools, equipment storage pool, and ICS heat exchangers are located outside of the RCCV, but inside the RB structure. In addition, the staff found that the description provided did not contain sufficient detail to confirm that three of the four ICS heat exchangers (minimum required for successful

heat removal) and the inner and outer expansion pools that provide heat exchanger cooling are adequately protected. In RAI 19.5-20 the staff asked the applicant to describe the structures that protect the ICS heat exchangers and water pools and how such protection ensures that three of the four ICS heat exchangers and sufficient water is available to remove decay heat. In their response, the applicant described inner and outer expansion pools located on opposite sides of the RB and indicated that both sides could not be damaged simultaneously by a large, commercial aircraft impact. They also stated that cross-connect valves between the equipment storage pool and the inner expansion pools are located in wells that protect them from damage. In addition, the applicant stated that check valves prevent loss of water from the inner expansion pool to its adjacent outer expansion pool. In addition the applicant stated that the aircraft impact assessment considers the potential for loss or diversion of pool water due to damage caused by a large, commercial aircraft impact and found that sufficient water is retained to provide adequate core cooling. The staff finds that the additional description of the design of the heat sink for the ICS heat exchangers, including features that prevent the loss or diversion of water from the inner expansion pools that directly support the heat exchangers, is adequate. Based on the applicant's response, RAI 19.5-20 is resolved.

The staff finds the applicant's description of the RB as a key design feature for providing physical protection for maintaining core cooling to be adequate.

19.2.7.3.3.4 Turbine Building and Fuel Building Structures

In DCD Tier 2, Revision 9, Appendix 19D, the applicant states that the location and design of the TB and FB structures, as shown in DCD Tier 2, Revision 9 general arrangement drawings (Figures 1.1-1, 1.2-1 through 1.2-20), are key design features that protect the RB from the impact of a large, commercial aircraft. The staff finds the applicant's description of the key design features for providing physical protection to the RB for maintaining core cooling to be adequate.

19.2.7.3.4 Integrity of the Spent Fuel Pool

The key design feature credited to maintain the integrity of the SFP is the location of the SFP structure as described in DCD Tier 2, Revision 9, Figures 1.2-1 through 1.2-4. The applicant states that the SFP structure is located entirely below grade and therefore, the SFP is protected from the impact of a large, commercial aircraft. The staff finds that the description of the key design feature for ensuring SFP integrity is adequate.

19.2.7.4 Conclusions

The staff finds that the applicant has performed an aircraft impact assessment that is reasonably formulated to identify design features and functional capabilities to show, with reduced use of operator action, that the acceptance criteria in 10 CFR 50.150(a)(1) are met. The staff finds that the applicant adequately describes the key design features credited to meet 10 CFR 50.150, including descriptions of how the key design features show that the acceptance criteria in 10 CFR 50.150(a)(1) are met. Therefore, the staff finds that the applicant meets the applicable requirements of 10 CFR 50.150(b).

19.2.8 Resolution of Generic Safety Issues

19.2.8.1 *Generic Letter (GL) 89-16 Installation of Hardened Wetwell Vent*

Generic letter (GL) 89-16, "Installation of Hardened Wetwell Vent," describes the safety benefits of installing a fixed vent pipe in the wetwell of boiling water reactors with a MARK I containment design and requests each licensee operating a BWR with a MARK I plant provide notification of its plans to install a hardened wetwell vent.

The ESBWR design does not include a MARK I containment design. However, a wetwell vent is part of the ESBWR design. The staff evaluated its effectiveness in Section 19.1.4.2.3 of this report and finds that the wetwell vent can be an effective means of averting containment failure, should it be needed.

Inclusion of a hardened wetwell vent in the ESBWR design adequately resolves the issues addressed in GL 89-16.

19.2.8.2 *TMI Action Plan Item II.B.8: Rulemaking Proceedings on Degraded Core Accidents*

Item II.B.8 discusses the need to establish policy, goals, and requirements to address accidents resulting in core damage greater than the existing design basis. The Commission expects that new designs will achieve a higher standard of severe accident safety performance than previous designs. In an effort to provide this additional level of safety in the design of advanced nuclear power plants, the NRC developed guidance and goals for designers to strive for in accommodating events that are beyond what was previously known as the design-basis of the plant.

For advanced passive nuclear power plants, like the ESBWR, the staff concludes that vendors should address severe accidents during the design stage to take full advantage of the insights gained from probabilistic safety assessments, operating experience, severe accident research and accident analysis by designing features to reduce the likelihood that severe accidents will occur and, in the unlikely occurrence of a severe accident, to mitigate the consequences of such an accident. Incorporating insights and design features during the design phase is much more cost effective than modifying existing plants. The NRC issued guidance for addressing severe accidents in the following documents:

- NRC Policy Statement, "Severe Reactor Accidents Regarding Future Designs and Existing Plants," issued August 8, 1985.
- NRC Policy Statement, "Safety Goals for the Operation of Nuclear Power Plants," issued August 4, 1986.
- NRC Policy Statement, "Nuclear Power Plant Standardization," issued September 15, 1987.
- 10 CFR Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants".
- SECY-90-016, "Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements," dated January 12, 1990, and the corresponding SRM dated June 26, 1990.

- SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs," dated April 2, 1993, and the corresponding SRM dated July 21, 1993.

The NRC policy statements provide guidance as to the appropriate course for addressing severe accidents, 10 CFR Part 52 contains general requirements for addressing severe accidents, and the SRMs relating to SECY-90-016 and SECY-93-087 offer Commission approved positions for implementing features in new designs for preventing severe accidents and mitigating their effects.

SECY-93-087 and 10 CFR Part 52 serve as the basis for resolving severe accident issues associated with the ESBWR. 10 CFR Part 52 requires (1) compliance with the TMI requirements in 10 CFR 50.34(f), (2) resolution of USIs and GSIs, and (3) completion of a design-specific PRA. The staff evaluates these criteria in Sections 19 and 20 of this report, respectively.

The Commission-approved positions on the issues discussed in SECY-93-087 form the basis of the staff's deterministic evaluation of severe accident performance for the ESBWR design. The staff evaluates the ESBWR design relative to these criteria in Section 19.2 of this report. Issue II.B.8 is resolved for the ESBWR design on the basis of the staff's evaluation of the probabilistic and deterministic analyses in the ESBWR PRA, as documented above.

19.2.8.3 *Generic Letter 88-20, Individual Plant Examination for Severe Accident Vulnerabilities*

The NRC issued GL 88-20 in November 1988, requesting that all reactor licensees perform an IPE to identify plant-specific vulnerabilities to severe accidents and report the results to the Commission. Each licensee developed a plant-specific PRA and used it to perform the requested IPE.

GEH has developed a PRA for the ESBWR and used it to identify vulnerabilities to severe accidents and evaluate alternative ways to eliminate such vulnerabilities. The results are documented in DCD Tier 2, Revision 9, Chapter 19. The staff has reviewed GEH's application of its PRA in the identification and elimination of severe accident vulnerabilities and finds it acceptable. The staff's evaluation is documented in Section 19.1 of this report. This resolves the issues addressed by GL 88-20 for the ESBWR.

19.2.8.4 *Generic issue 157: Containment Performance*

The results of NRC-sponsored research which culminated in the assessment of risk at five U.S. nuclear reactors in the late 1980s indicated that, for the Peach Bottom boiling water reactor, the core-melt probability was relatively low. However, it also indicated that the containment could be severely challenged if a large core-melt occurred. The Peach Bottom design includes the MARK I containment design. Consequently, the NRC decided to examine MARK I plants for potential plant and containment modifications to improve containment performance. Subsequently, this examination was expanded to include all other types of containment utilized at nuclear power plants regulated by the NRC. These studies were conducted under the Containment Performance Improvement (CPI) program. In some cases, these studies revealed highly beneficial design improvements (see discussion of the hardened wet well vent above in Section 19.2.8.1 of this report.)

GEH has performed probabilistic and deterministic assessments of ESBWR containment performance and documented them in DCD Tier 2, Revision 9, Appendices 19B and 19C. The staff reviewed these assessments and documented its results in Section 19.2.4 of this report. The staff finds that the applicant's containment performance evaluation meets the requirement of 10 CFR 50.44, the SECY-93-087 expectation for containment structural performance, and the staff's expectation of the quality of the containment pressure fragility analysis. This resolves the issues addressed by Generic Issue 157 for the ESBWR.

19.2.9 Conclusion

As discussed in Section 19.1 of this report, the applicant made extensive use of the results of the PRA to arrive at a final ESBWR design. As a result, the estimated CDF and risk calculated for the ESBWR design are very low. The low CDF and risk for the ESBWR design reflect the applicant's efforts to systematically minimize the effect of initiators and sequences that have been important contributors to CDF in previous BWR PRAs. The applicant achieved this minimization largely through the incorporation of hardware improvements in the ESBWR design. Section 19.2 of this report discusses these improvements and the additional ESBWR design features that contribute to low CDF and risk for the ESBWR.

Because the ESBWR design already contains many plant features aimed at reducing CDF and risk, the benefits and risk reduction potential of additional plant improvements are significantly reduced. This reduction applies to both internally and externally initiated events. Moreover, with the features already incorporated in the ESBWR design, the ability to estimate CDF and risk approaches the limits of probabilistic techniques.

The staff evaluated the applicant's severe accident evaluation and identified several issues that were not adequately addressed. The applicant has now addressed all of these issues adequately through its responses to the staff's RAIs and the follow-up activities identified in the audit report. The staff has described each open issue and the basis for resolution of the issue in the appropriate section of this report. Based on its review, the staff finds that the applicant has adequately addressed the Commission's objectives, described above in Section 19.1.1, regarding the prevention and mitigation of severe accidents.

20.0 GENERIC ISSUES

20.1 Introduction

This chapter discusses the staff's evaluation of unresolved safety issues (USIs) and generic safety issues (GSIs), Three Mile Island (TMI) action plan items addressed in Title 10 of the *Code of Federal Regulations* (10 CFR) 50.34(f), and incorporation of operating experience in the economic simplified boiling-water reactor (ESBWR) design submitted by GE-Hitachi Nuclear Energy (GEH). Since there are a large number of generic issues (GIs) relevant to the ESBWR design, this chapter predominantly directs the reader to other chapters and sections of the safety evaluation report (SER) that present the staff's evaluation of GIs. However, this section of the report does specifically address some GIs.

Tables 20.1-1, 20.1-2, and 20.1-3 list all GIs relevant to the ESBWR design and the SER chapters or sections where they are addressed. Table 20.1-1 lists GSIs and USIs, which include task action plan items, new GIs, TMI action plan items, and human factor issues as identified in NUREG-0933, "A Prioritization of Generic Safety Issues." Table 20.1-2 lists TMI action plan items addressed in 10 CFR 50.34(f). Table 20.1-3 lists generic letters (GLs) and bulletins (BLs) that deal with operating experience.

The staff's evaluations of GIs described in this chapter are grouped according to issue type. Section 20.2 contains task action plan items which include both USIs and GSIs. Section 20.3 addresses new GIs, which are categorized as GSIs. Section 20.4 addresses TMI action plan items, which includes those required by 10 CFR 50.34(f) and those GSIs identified in NUREG-0933.

20.1.1 **Compliance with 10 CFR 52.47(a)(21)**

10 CFR 52.47(a)(21) requires an application for design certification (DC) to include proposed technical resolutions of the USIs and medium- and high-priority GSIs as defined in NUREG-0933. These issues must be technically relevant to the design and are identified in the applicable NUREG-0933 supplement that was current 6 months before the docket date of the application.

In design control document (DCD) Tier 2, Revision 9, Table 1.11-1 in Section 1.11 and Table 1A-1 in Appendix 1A, the applicant addressed the USIs and GSIs relevant to the ESBWR design. The staff evaluation of the resolution of the USIs and GSIs is described in the SER sections listed in Table 20.1-1. Table 20.1-1 provides the issue designation, title, and SER section that address the issue. The USIs and GSIs listed in Table 20.1-1 include task action plan items, new GIs, and TMI action plan items.

20.1.2 **Compliance with 10 CFR 52.47(a)(8)**

According to 10 CFR 52.47(a)(8), a design certification applicant must demonstrate compliance with any technically relevant parts of the TMI action plan requirements found in 10 CFR 50.34(f). The applicant addressed these requirements in DCD Tier 2, Revision 9, Table 1A-1 in Appendix 1A. Because of the overlap between the TMI action plan requirements and the GSIs identified in NUREG-0933, Table 20.1-2 lists all the relevant parts of the TMI action plan items found in 10 CFR 50.34(f) in tabular form. Table 20.1-2 provides the issue designation, the 10 CFR 50.34(f) requirements, and the SER section in which they are addressed. Staff's evaluation of

the resolution of the TMI Action Plan items are described in the designated SER sections listed in Tables 20.1-1 and 20.1-2.

20.1.3 Incorporation of Operating Experience

As part of its program to disseminate information on operating experience to the nuclear industry, the U.S Nuclear Regulatory Commission (NRC) issues generic communications when a significant safety-related event or condition at a facility may potentially apply to other facilities. The generic communications are issued in form of GLs, BLs, and information notices (INs). The NRC issues GLs and BLs when the event or condition requires the licensees to inform the NRC of what actions they have taken or will take to address the event or condition that is potentially significant to safety. The agency issues INs when it has determined that licensees should be informed of an event or condition but the communication does not contain any requests for action by the licensees. Potential safety issues highlighted in NRC generic communications may be incorporated into formal requirements or may eventually become a USI or GSI.

In the staff requirements memorandum (SRM), dated February 15, 1991, concerning SECY-90-377, "Requirements for Design Certification Under 10 CFR Part 52," dated November 8, 1990, the Commission directed the staff to ensure that the design certification process preserves operating experience insights in the certified design. In the NRC program to review and incorporate operating experience, the BLs and GLs that are issued to the nuclear industry convey the most safety-significant lessons distilled from many sources of information. In contrast, INs do not require action by the licensees.

The applicant addressed incorporation of operating experience in DCD Tier 2, Revision 9, Tables 1C-1 and 1C-2 in Appendix 1C. The SER sections listed in Table 20.1-3 describe the staff's evaluation of the applicant's incorporation of operating experience in the ESBWR design. The table provides issue designation, title, and, the SER section that addresses the issue.

Table 20.1-1. USIs and GSIs in NUREG-0933 Relevant to the ESBWR Design.

ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
	Task Action Plan Items	
A-1	Water Hammer	3.12, 10.3, 10.47
A-6	Mark I Short Term Program	6.2.1.3.3
A-7	Mark I Long Term Program	6.2.1.3.3
A-8	Mark II Containment Pool Dynamic Loads-Long Term Program	6.2.1.3.3
A-9	ATWS (Former USI)	15.6.4
A-10	BWR Feed Water Nozzle Cracking	5.3.1.2, 10.4.7
A-11	Reactor Vessel Materials Toughness (Former USI)	5.3.1.2
A-13	Snubber Operability Assurance	3.9.6,

ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
A-17	Systems Interactions in Nuclear Power Plants (Former USI)	20.2
A-19	Digital Computer Protection System	7.1
A-23	Containment Leak Testing	6.2.3
A-24	Qualification of Class 1E Safety-Related Equipment	3.11
A-25	Non-Safety Loads on Class 1E Power Sources	8.3.1
A-28	Increase in Spent Fuel Pool Storage Capacity	9.1.3
A-29	Nuclear Power Plant Design for the Reduction of Vulnerability to Industrial Sabotage	13.6
A-30	Adequacy of Safety-Related DC Power Supplies	8.3.2
A-31	RHR Shutdown Requirements	20.2
A-34	Instruments for Monitoring Radiation and Process Variables During Accidents	7.5
A-35	Adequacy of Offsite Power Systems	8.2
A-36	Control Heavy Loads Near Spent Fuel	9.1.5
A-39	Determination of Safety Relief Valve Pool Dynamic Loads and Temperature Limits	6.2.1.3.3
A-40	Seismic Design Criteria Short Term Program	3.7.1, 3.7.2, 3.7.3
A-42	Pipe Cracks in Boiling Water Reactors	5.2.3
A-44	Station Blackout	8.4
A-45	Shutdown Decay Heat Removal Requirements	20.2
A-46	Seismic Qualification of Equipment in Operating Plants (Former USI)	3.10.3.6
A-47	Safety Implications of Control Systems (Former USI)	7.7
A-48	Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment	6.2.5
B-6	Loads, Load Combinations, Stress Limits	3.8.1, 3.8.2, 3.8.3, 3.8.4, 3.8.5
B-10	Behavior of BWR Mark III Containments	6.2.1.3.3

ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
B-12	Containment Cooling Requirements (Non-LOCA)	6.2.2.3
B-17	Criteria for Safety-Related Operator Actions	18.15.2
B-19	Thermal-Hydraulic Stability	4.4
B-26	Structural Integrity of Containment Penetrations	3.81, 3.8.2
B-36	Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Feature Systems and For Normal Ventilation Systems	6.4
B-48	BWR Control Rod Drive Mechanical Failures	4.5.1
B-55	Improved Reliability of Target Rock Safety Relief Valves	20.2
B-60	Loose Parts Monitoring System	4.4
B-63	Isolation of Low Pressure Systems Connected to the Reactor Coolant Pressure Boundary	20.2
B-66	Control Room Infiltration Measurements	6.4
B-67	Effluent and Process Monitoring Instrumentation	11.5
C-1	Assurance of Continuous Long Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment	20.2
C-2	Study of Containment Depressurization by Inadvertent Spray Operation to Determine Adequacy of Containment External Design Pressure	6.2.1
C-4	Statistical Methods for ECCS Analysis	6.3, 21.6
C-5	Decay Heat Update	6.3
C-6	LOCA Heat Sources	6.3
C-11	Assessment of Failure and Reliability of Pumps and Valves	20.2
C-17	Interim Acceptance Criteria for Solidification Agents for Radioactive Solid Wastes	11.4
D-3	Control Rod Drop Accident	15.4

ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
	New Generic Issues	
6	Separation of Control Rod from Its Drive and BWR High Rod Worth Events	4.6
15	Radiation Effects on Reactor Vessel Supports	5.3.3
29	Bolting Degradation or Failure in Nuclear Power Plants	3.13
45	Inoperability of Instrumentation Due to Extreme Cold Weather	7.1
51	Proposed Requirements for Improving Reliability the Open Cycle Service Water System	9.2.1
57	Effects of Fire Protection System Actuation on Safety-Related Equipment	20.3
64	Identification of Protection System Instrument Sensing Lines	7.1
67.3.3	Steam Generator Staff Actions - Improved Accident Monitoring	7.5
75	Generic Implication of ATWS Events at the Salem Nuclear Plant	20.3
78	Monitoring of Fatigue Transient Limits for Reactor Core Coolant System	3.12, 16
80	Pipe Break Effects on Control Rod Drive Hydraulic Lines in the Drywells of BWR Mark I and Mark II Containments	20.3
83	Control Room Habitability	6.4
86	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	5.2.3
103	Design for Probable Maximum Precipitation	2.4.3
105	Interfacing Systems LOCA at LWRs	20.3
106	Piping and the Use of Highly Combustible Gases in Vital Areas	20.3
107	Main Transformer Failures	8.3.1
111	Stress Corrosion Cracking of Pressure Boundary Ferritic Steels in Selected Environment	5.2.3

ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
113	Dynamic Qualification Testing of Large Bore Hydraulic Snubbers	3.9.3
119.1	Piping Rupture Requirements and Decoupling of Seismic and LOCA Loads	3.6.2
119.2	Piping Damping Values	3.12
119.3	Decoupling the OBE from the SSE	3.12
119.4	BWR Piping Materials	5.2.3, 6.1.1
120	On-Line Testability of Protection Systems	16
142	Leakage through Electrical Isolators in Instrumentation Circuits	7
143	Availability of Chilled Water Systems and Room Cooling	9.2.7
146	Support Flexibility of Equipment and Components	3.9.2
153	Loss of Essential Service Water in LWRs	9.2.1
156.6.1	Systematic Evaluation Program - Piping Break Effects on Systems and Components	3.6.2, 3.9.3, 3.8.1, 3.8.3
157	Containment Performance	19.2.8
166	Adequacy of Fatigue Life of Metal Components	3.12.6.7
173.A	Spent Fuel Storage Pool – Operating Facilities	9.1.3
186	Potential Risk and Consequences of Heavy Loads in Nuclear Power Plants	9.1.5
189	Susceptibility of Ice Condenser and Mark III Containments to Early Failure from Hydrogen Combustion During a Severe Accident	20.3
191	Assessment of Debris Accumulation on PWR Sump Performance	6.2.1
193	BWR ECCS Suction Concerns	20.3

ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
	Three Mile Island Action Plan Items	
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff	20.4
I.C.9	Long -Term Program Plan for Upgrading of Procedures	20.4
I.D.1	Control Room Design Review	18.15.3
I.D.2	Plant Safety Parameter Display Console Description	18.15.3
I.D.3	Safety System Status Monitoring	7
I.F.1	Expand QA list	20.4
I.F.2	Develop More Detailed QA Criteria	20.4
II.B.1	Reactor Coolant System Vents	5.4.12
II.B.2	Plant Shielding To Provide Access to Vital Areas and Protect Safety Equipment for Post-Accident Operation	3.11, 12.4.3.5
II.B.3	Post- Accident Sampling	11.5
II.B.8	Rulemaking Proceedings on Degraded Core Accidents	19.2.8.2
II.D.1	Testing Requirements	5.2.2
II.D.3	Relief and Safety Valve Position Indication	5.2.2
II.E.4.2	Isolation Dependability	6.2.4
II.E.4.4	Purging	6.2.4
II.F.1	Additional Accident Monitoring Instrumentation	7.5, 12.4.3.4
II.F.2	Identification of and Recovery from Conditions Leading to Inadequate Core Cooling	7.1.1.3.4
II.F.3	Instruments for Monitoring Accident Conditions	7.5
II.J.3.1	Organization and Staffing To Oversee Design and Constructions	20.4
II.K.1(22)	Describe Automatic and Manual Actions for Proper Functioning of Auxiliary Heat Removal System When Feedwater System Not Operable	20.4
II.K.2(10)	Hard-Wired Safety Grade Anticipatory Reactor Trips	7.4
II.K.3(13)	Separation of HPCI and RCIC System Initiation Levels	20.4

ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
II.K.3(16)	Reduction of Challenges and Failures of Relief Valves- Feasibility Study and System Modification	5.2.2
II.K.3(18)	Modification of ADS Logic- Feasibility Study and Modification for Increased Diversity for Some Events Sequences	7.3
II.K.3(21)	Restart of Core Spray and LPCI Systems on Low Level-Design and Modification	6.3
II.K.3(23)	Central Water Level Recording	7
II.K.3(24)	Confirm Adequacy of Space Cooling for HPCI and RCIC Systems	6.3
II.K.3(28)	Study and Verify Qualification of Accumulators on ADS Valves	20.4
II.K.3(45)	Evaluate Depressurization with Other Than Full ADS	5.3.2
III.A.1.2(1)	Technical Support Center	13.3
III.A.1.2(2)	Onsite Operational Support Center	13.3
III.D.1.1	Primary Coolant Sources Outside the Containment Structure	20.4
III.D.3.3	In-Plant Radiation Monitoring	12.6
III.D.3.4	Control Room Habitability	6.4
	Human Factors Issues	
HF1.1	Shift Staffing	18.6, 18.15.1
HF4.4	Guidelines for Upgrading Other Procedures	18.9, 18.15.2
HF4.5	Application of Automation and Artificial Intelligence	18.3
HF5.1	Local Control Stations	18.15.2
HF5.2	Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation	18.8, 18.15.2

Table 20.1-2. 10 CFR 52.47(a)(8) TMI Action Plan Items.

TMI REQUIREMENT	10 CFR 50.34(F)	SER CHAPTER/ SECTION
I.C.5	(3)(i)	20.4
I.C.9	(2)(ii)	20.4
I.D.1	(2)(iii)	18.15.3
I.D.2	(2)(iv)	18.15.3
I.D.3	(2)(v)	7
I.F.1	(3)(ii)	20.4
I.F.2	(3)(iii)	20.4
II.B.1	(2)(vi)	5.4.12
II.B.2	(2)(vii)	3.11, 12.4.3.5
II.B.3	(2)(viii)	11.5
II.B.8	(1)(i) & (xii), (2)(ix), (3)(iv) & (v)	19.2.8.2
II.D.1	(2)(x)	5.2.2
II.D.3	(2)(xi)	5.2.2
II.E.4.2	(2)(xiv)	6.2.4
II.E.4.4	(2)(xv)	6.2.4
II.F.1	(2)(xvii)	7.5, 12.4.3.4
II.F.2	(2)(xviii)	7.1.1.3.4
II.F.3	(2)(xix)	7.5
II.J.3.1	(3)(vii)	20.4
II.K.1(22)	(2)(xxi)	20.4
II.K.2(10)	(2)(xxiii)	7.4
II.K.3(13)	(1)(v)	20.4
II.K.3(16)	(1)(vi)	5.2.2
II.K.3(18)	(1)(vii)	7.3
II.K.3(23)	(2)(xxiv)	7
II.K.3(21)	(1)(viii)	6.3

TMI REQUIREMENT	10 CFR 50.34(F)	SER CHAPTER/ SECTION
II.K.3(24)	(1)(ix)	6.3
II.K.3(28)	(1)(x)	20.4
II.K.3(45)	(1)(xii)	5.2.3
III.A.1.2(1)	(2)(xxv)	13.3
III.D.1.1	(2)(xxvi)	20.4
III.D.3.3	(2)(xxvii)	12.6
III.D.3.4	(2)(xxviii)	6.4

Table 20.1-3. Generic Letters and Bulletins.

ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
	Generic Letters	
GL 80-09	Low Level Radioactive Waste Disposal	11.4
GL 80-34	Clarification of NRC Requirements for Emergency Response Facilities at Each Site	13.3
GL 80-113	Controls of Heavy Loads	9.1.5
GL 81-04	Emergency Procedures and Training for Station Blackout Events	18.15.4
GL 81-03	Implementation of NUREG–0313, Revision 1, “Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping (Generic Task A-42)”	5.2.3
GL 81-07	Control of Heavy Loads	9.1.5
GL 81-10	Post TMI Requirements for the Emergency Operations Facility	13.3
GL 81-11	“BWR Feedwater Nozzle and Control Rod Nozzle Drive Return Line Nozzle Cracking” (NUREG -0619)	10.4.7
GL 81-20	Safety Concerns Associated with Pipe Breaks in the BWR Scram System	20.5.1
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GL 82-09	Environmental Qualification of Safety-Related Electrical Equipment	3.11
GL 82-21	Technical Specifications for Fire Protection Audits	16
GL 82-23	Inconsistency Between Requirement of 10 CFR 73.40(D) and Standard Technical Specifications for Performing Audits of Safeguards Contingency Plans	16
GL 82-27	Transmittal of NUREG 0763, "Guidelines for Confirmatory In-Plant Tests of Safety Relief Valve Discharges for BWR Plants," and NUREG 0783, "Suppression Pool Temperature Limits for BWR Containments"	6.2.1.1.6
GL 82-33	Supplement 1 to NUREG-0737 – Requirements for Emergency Response Capability	7.1.1.3.5, 13.3 and 18.15.3
GL 83-05	Safety Evaluation of "Emergency Procedure Guidelines Revision 2," NEDO-24934, June 1982	18.9, 13.5
GL 83-13	Clarification of SRs Surveillance Requirements for HEPA Filters and Charcoal Adsorber Units in STS and ESP Standard Technical Specifications of ESF Cleanup Systems	6.2.3
GL 83-28	Required Actions Based on Generic Implications of Salem ATWS Events	20.5.1
GL 83-33	NRC Positions on Certain Requirements of Appendix R to 10 CFR Part 50	20.5.1
GL 84-15	Proposed Staff Actions To Improve and Maintain Diesel Generator Reliability	8.3.1
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GL 85-01	Fire Protection Policy Steering Committee Report	20.5.1
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GL 88-16	Removal of Cycle-Specific Parameter Limits from Technical specifications	16
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GL 89-07	Powers Reactor Safeguards Contingency Planning for Surface Vehicle Bombs	13.6
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GL 89-10	Safety-Related Motor-Operated Valve Testing and Surveillance	3.9.6
GL 89-13	Service Water System Problems Affecting Safety-Related Equipment	9.2.1
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ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
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GL 89-16	Installation of a Hardened Wetwell Vent	19.2.8.1
GL 89-18	Resolution of Unresolved Safety Issue A-17, "System Interactions in Nuclear Power Plants"	20.5.1
GL 89-19	Request for Action Related to Resolution of Unresolved Safety-Related Issue A-47, "Safety Implication of Control Systems in LWR Nuclear Power Plants" Pursuant to 10 CFR 50.54(f)	7.7
GL 89-22	Potential for Increased Roof Loads and Plant Area Flood Runoff Depth at Licensed Nuclear Power Plants Due to Recent Change in Probable Maximum Precipitation Criteria Developed by the National Weather Service	3.8.4
GL 90-09	Alternative Requirements for Snubber Visual Inspection Intervals and Corrective Actions	3.9.6
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GL 91-03	Reporting of Safeguards Events	13.6
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GL 91-06	Resolution of Generic Issue A-30, "Adequacy of Safety-Related DC Power Supplies," Pursuant to 10 CFR 50.54(f)	20.5.1
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GL 91-11	Resolution of Generic Issues 48, "LCOs for Class 1E Vital Instrumentation Bus," and 49, "Interlocks and LCOs for Class 1E Tie Breakers" Pursuant to 10 CFR 50.54(f)	8.3.1
GL 91-14	Emergency Telecommunications	9.5
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GL 91-17	Generic Safety Issue 29, "Bolting Degradation or Failure in Nuclear Power Plants"	3.13
GL 92-01	Reactor Vessel Structural Integrity	5.3.1.2
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ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
GL 92-08	Thermo-Lag 330-1 Fire Barriers (BL 92-001)	20.5.1
GL 93-05	Line-Item in Technical Specifications Improvements To Reduce Surveillance Requirements for Testing During Power Operations	16
GL 93-06	Research Results on Generic Safety Issue 106, "Piping and the Use of Highly Combustible Gases in Vital Areas," October 25, 1993	20.5.1
GL 93-08	Relocation of Technical Specifications Tables of Instrument Response Time Limits	16
GL 94-01	Removal of Accelerated Testing and Special Reporting Requirements for Emergency Diesel Generators	8.3.1
GL 94-02	Long-Term Solutions and Upgrade of Interim Operating Recommendation for Thermal-Hydraulic Instabilities in Boiling Water Reactors	4.4
GL 94-03	Intergranular Stress Corrosion Cracking of Core Shrouds in BWRs	4.5.2
GL 95-07	Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves	3.9.6
GL 96-01	Testing of Safety-Related Logic Circuits	7.1
GL 96-03	Relocation of the Pressure Temperature Limit Curves and Low Temperature Overpressure Protection System Limits	16
GL 96-04	Boraflex Degradation in Spent Fuel Pool Storage Racks	9.1.2
GL 96-05	Periodic Verification of Design Basis Capability of Safety-Related Motor -Operated Valves	3.9.6
GL 96-06	Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions	6.2.1
GL 97-04	Assurance of Sufficient Net Positive Suction Head for Emergency Core Cooling System and Containment Heat Removal Pumps	6.2.2, 6.3
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ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
GL 2003-01	Control Room Habitability	6.4
GL 2006-03	Potentially Nonconforming Hemyc and MT Fire Barrier Configurations, April 10, 2006	20.5.1
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BL 79-02	Pipe Support Base Plate Designs Using Concrete Expansion Anchor Bolts	3.12
BL 80-01	Operability of ADS Valve Pneumatic Supply	20.5.2
BL 80-03	Loss of Charcoal from Standard Type II, 2 Inch, Tray Adsorber Cells	6.2.3
BL 80-06	Engineered Safety Features (ESF) Reset Controls	7.3
BL 80-08	Examination of Containment Liner Penetration Welds	6.6
BL 80-10	Contamination of Nonradioactive System, and Resulting Potential for Unmonitored, Uncontrolled Release of Radioactivity to the Environment	11.2, 11.3, 11.4, 11.5
BL 80-15	Possible Loss of Emergency Notification System (ENS) with Loss of Offsite Power	9.5
BL 80-24	Prevention of Damage Due to Water Leakage Inside Containment	9.2.7
BL 80-25	Operating Problems with Target Rock Safety-Relief Valves at Boiling Water Reactors	20.5.2
BL 81-01	Surveillance of Mechanical Snubbers	3.9.6
BL 81-03	Flow Blockage of Cooling Water to Safety System Components by Corbicula sp. (Asiatic Clam) and Mytilus sp. (Mussel)	9.2.1
BL 82-04	Deficiencies in Primary Containment Electrical Penetration Assemblies	8.3.1
BL 85-03	Motor-Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings	20.5.2
BL 86-01	Minimum Flow Logic Problems That Could Disable RHR Pumps	20.5.2
BL 87-01	Thinning of Pipe Walls In Nuclear Power Plants	6.6, 10.3.6
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ISSUE DESIGNATION	TITLE	SER CHAPTER/ SECTION
BL 88-08	Thermal Stresses in Piping Connected to Reactor Coolant Systems	3.12
BL 90-02	Loss of Thermal Margin Caused by Channel Box Bow	4.2
BL 93-02	Debris Plugging of Emergency Core Cooling Systems Suction Strainers	6.2.1
BL 93-03	Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in Boiling Water Reactors	20.5.2
BL 94-01	Potential Fuel Pool Draindown Caused by Inadequate Maintenance Practices at Dresden Unit 1	9.1.3
BL 95-02	Unexpected Clogging of a Residual Heat Removal Pump Strainer While Operating in Suppression Pool Cooling Mode	6.2.1
BL 96-02	Movement of Heavy Loads over Spent Fuel, over Fuel in the Reactor Core, or over Safety-Related Equipment	9.1.5
BL 96-03	Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors	6.2.1
BL 05-02	Emergency Preparedness and Response Actions for Security- Based Events	13.3

20.2 Task Action Plan Items

This section addresses the staff's evaluation of USIs and GSIs that are categorized as "task action plan items" in NUREG-0933.

A-17: Systems Interactions in Nuclear Power Plants

As discussed in NUREG-0933, Issue A-17 addresses concerns about adverse system interactions (ASIs) in nuclear power plants. Depending on how they propagate, ASIs can be classified as functionally coupled, spatially coupled, and induced-human-intervention coupled. As discussed in NUREG-1229, "Regulatory Analysis for Resolution of USI A-17," issued August 1989, and GL 89-18, "Resolution of Unresolved Safety Issue A-17, Systems Interactions in Nuclear Power Plants," dated September 6, 1989, Issue A-17 concerns ASIs caused by water intrusion, internal flooding, seismic events, and pipe ruptures.

A nuclear power plant is comprised of numerous structures, systems, and components (SSCs) that are designed, analyzed, and constructed using many different engineering disciplines. The degree of functional and physical integration of these SSCs into any single power plant may vary considerably. Concerns have been raised about the adequacy of this functional and physical integration and the coordination process. The Issue A-17 program was initiated to integrate the areas of systems interactions and to consider viable alternatives for regulatory requirements to ensure that ASIs have been or will be minimized in operating and new plants.

Within the framework of the program, the staff requested, as stated in NUREG–0933, that plant designers consider the operating experience discussed in GL 89-18 and use the probabilistic risk assessment (PRA) required for future plants to identify vulnerability and reduce ASIs.

Issue A-17 concerns the need to investigate the potential that unrecognized subtle dependencies, or systems interactions, among SSCs in a plant could lead to safety-significant events. In NUREG–1174, “Evaluation of Systems Interactions in Nuclear Power Plants: Technical Findings Related to Unresolved Safety Issue A-17,” issued May 1989, inter-system dependencies are categorized based on the way they propagate into functionally coupled, spatially coupled, and induced-human-intervention coupled systems interactions. The occurrence of an actual ASI or the existence of a potential ASI, as well as the potential overall safety impact, is a function of an individual plant’s design and operational features. For the ESBWR with new or differently configured passive and active systems, a systematic search for ASIs is necessary.

The applicant used a systematic process to analyze specific features and actions that are designed to prevent postulated adverse interactions. In its response to request for additional information (RAI) 19.1.0-2, the applicant submitted an assessment of significant adverse interactions.

The purpose of the applicant’s assessment was to identify possible adverse interactions among safety-related systems (passive systems) and between safety-related and non-safety-related systems (active systems), and to evaluate the potential consequences of such interactions. The assessment evaluated the gravity-driven cooling system (GDCS), automatic depressurization system (ADS), isolation condenser system (ICS), standby liquid control system (SLCS), and passive containment cooling system (PCCS). Interaction of these systems with other systems, such as fuel and auxiliary pools cooling system (FAPCS), direct current power, suppression pool, main steam, containment, high pressure nitrogen supply system, and radiation monitoring system, was studied by the applicant. The staff reviewed this study as part of their review of the regulatory treatment of non-safety systems (RTNSS) as described in Chapter 22.5.5 of this report. For the purpose of the staff’s analysis, an adverse system interaction exists if the action or condition of an active, interfacing system causes a loss of safety function of a passive system.

The applicant addresses Issue A-17 in DCD Tier 2, Revision 9, Table 1.11-1. Based on the above information and the staff’s evaluation in Section 22.5.5 of this report, the staff concludes that the applicant has adequately assessed possible ASIs and their potential consequences and issue A-17 is resolved for the ESBWR design.

A-31: RHR Shutdown Requirements (former USI)

As discussed in NUREG–0933, Issue A-31 addresses the ability of a plant to transfer heat from the reactor to the environment after shutdown, which is an important safety function. This issue was resolved in 1978 with the issuance of NUREG–0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants (LWR Edition),” (SRP) March 2007, Section 5.4.7.

As described in NUREG–0933, the safe shutdown of a nuclear power plant following an accident not related to a loss-of-coolant accident (LOCA) has typically been interpreted by the staff as achieving “hot-standby” condition (i.e., the reactor is shutdown, but system temperature and pressure are still at or near normal operating values). The NRC has placed an emphasis

on the hot-standby condition of a power plant in the event of an accident or other abnormal occurrence, as well as on long-term cooling, which is typically achieved by the RHR system. The RHR system starts to operate when the reactor coolant pressure and temperature are substantially lower than the values for the hot-standby condition. Although it may generally be considered safe to maintain a reactor in hot-standby condition for a long time, experience shows that certain events have occurred that required eventual cooldown or long-term cooling until the reactor coolant system (RCS) was cold enough for personnel to inspect and repair the problem.

In Appendix A to 10 CFR Part 50, General Design Criteria (GDC) 34, "Residual heat removal," the NRC requires an RHR system to be provided with suitable redundancy in components and features to ensure that, with or without onsite or offsite power, it can accomplish its safety functions so as not to exceed the specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary (RCPB). The Electric Power Research Institute (EPRI) Utility Requirements Document (URD) proposes that the safe shutdown condition be defined as less than 215.6 degrees Celsius (C) (420 degrees Fahrenheit [F]) for the passive advanced light-water reactor (ALWR) designs. In its evaluation of the URD, the staff concluded that cold shutdown is not the only safe stable shutdown condition able to maintain the fuel and RCPB within acceptable limits. In SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs," Section C, "Safe Shutdown Requirements," dated March 28, 1984, the staff recommended, and the Commission approved, that the EPRI-proposed 215.6 degrees C (420 degrees F) criterion or below, rather than the cold-shutdown condition described in SRP 5.4.7, be accepted as a safe stable condition, which the passive ICS system must be capable of achieving and maintaining following non-LOCA events. The staff's acceptance is predicated on an acceptable passive safety system performance and an acceptable resolution of the issue of RTNSS for reactor water cleanup (RWCU) system.

SECY-94-084 also states that the passive safety system capabilities can be demonstrated by appropriate evaluations during detailed design analyses, including the following two analyses:

- (1) A safety analysis to demonstrate that the passive systems can bring the plant to a safe stable condition and maintain this condition such that no transients will violate the specified acceptable fuel design limits and pressure boundary design limit, and that no high-energy piping failure initiated by this condition will violate the 10 CFR 50.46 criteria, i.e., emergency core cooling system (ECCS) acceptance criteria for light-water nuclear power reactors
- (2) A probabilistic reliability analysis, including events initiated from the safe-shutdown conditions, to ensure conformance with the safety goal guidelines and to determine the reliability and availability missions of risk-significant systems and components as a part of the effort for regulatory treatment of non-safety systems (RTNSS)

In DCD Tier 2, Table 1.11, the applicant addresses this issue. The applicant states that the ESBWR is a passive plant and does not have the traditional RHR system. The applicant stated that the isolation condensers (ICs) can achieve and maintain a safe stable condition for at least 72 hours without operator action following non-LOCA events. DCD Tier 2, Revision 9, Section 5.4.6 discusses the ICS. DCD Tier 2, Revision 9, Sections 5.4.7 and 5.4.8 discuss the non-safety-related normal RWCU system. For normal shutdown and cooldown, residual and decay heat is removed via the main condenser and the shutdown cooling (SDC) mode of the RWCU. The RWCU system consists of two redundant trains. In the event of loss-of-preferred power, the RWCU/SDC system, in conjunction with the ICs, is capable of bringing the reactor pressure

vessel (RPV) to the cold shutdown condition in a day and a half, assuming a limiting single active failure, and with the ICs removing the initial heat load.

The staff agrees with the applicant that for the ESBWR design, cold-shutdown conditions can be achieved using reliable, but non-safety-related systems, which have redundancy similar to that of the current generation safety-related systems and are supplied with alternating current power from either onsite or offsite sources. Sections 5.4.7 and 5.4.8 of this report provide the staff's evaluation of the RWCU system. Section 5.4.6 of this report provides the staff's evaluation of the ICS. The staff concludes that the ESBWR design complies with GDC 34 by using a more reliable and simplified system for both hot-standby and long-term cooling modes of the RWCU system. The staff also concludes that it is not necessary that these passive systems achieve cold shutdown as discussed in SECY-94-084.

Section 22.5 of this report discusses the RTNSS issue in terms of the availability of the RWCU/SDC and ICS system during shutdown and refueling conditions. Based on the above discussion and the staff's evaluation in Sections 5.4.6, 5.4.7, 5.4.8, and 22.5 of this report, the staff considers Issue A-31 resolved for the ESBWR design.

A-45: Shutdown Decay Heat Removal Requirements

In March 1981, NUREG-0705, "Identification of New Unresolved Safety Issues Relating to Nuclear Power Plants—Special Report to Congress," designated this issue as a USI. The NRC initiated a program to evaluate the adequacy of the decay heat removal (DHR) function in operating light-water reactors (LWRs) and to assess the value and impact (i.e., the benefit and cost) of alternative measures to improve the overall reliability of the DHR function.

According to NUREG-0933, the program employed PRAs and deterministic evaluations of those DHR systems and support systems required to achieve hot shutdown and cold shutdown conditions in both pressurized water reactors (PWRs) and boiling-water reactors (BWRs). Systems analysis techniques were used to assess the vulnerability of DHR systems to various internal and external events. The analyses were limited to transients, small-break LOCAs, and special emergency challenges such as fires, floods, earthquakes, and sabotage. Cost-benefit analysis techniques were used to assess the net safety benefit and cost of alternative measures to improve the overall reliability of the DHR function.

Establishing a safe-shutdown condition requires maintenance of the reactor in a subcritical condition and adequate cooling to remove residual heat. One of the functional requirements for the ESBWR is that the plant can be brought to a stable condition using the safety-grade systems for all events. Because of the potential functional limitations of the safety-related passive plant designs, the Commission, in a SRM dated June 30, 1994 from John C Hoyle to James M. Taylor, SECY-94-084, "Policy and technical Issues associated with the regulatory treatment of non-safety systems, COMSECY-94-024, Implementation of design certification and light water reactor design issues", approved the position proposed in SECY-94-084. This position accepts 215.6 degrees C (420 degrees F) or below, rather than the cold shutdown (i.e., less than 93.3 degrees C [200 degrees F]) specified in SRP reactor systems branch (RSB) Branch Technical Position, RSB BTP 5-1, as the safe stable condition that the passive decay heat removal system must be capable of achieving and maintaining following non-LOCA events. The SLCS establishes safe shutdown by providing the necessary reactivity control to maintain the core in a subcritical condition while ICS provides residual heat removal capability to maintain adequate core cooling. DCD Tier 2, Revision 9, Sections 5.4, 6.3, 7.4, discuss the systems required for safe shutdown:

- ICS
- SLCS
- Safety/relief valves (SRVs)
- Depressurization valves (DPVs)
- GDCS
- PCCS

The passive ICS is automatically initiated upon closure of the main steam isolation valves (MSIVs) to remove decay heat following scram and isolation, and ICS condensate flow provides initial reactor coolant inventory makeup to the RPV. If the water reaches Level 1 in the reactor, the ADS, with the operation of the SRVs and DPVs, is initiated to depressurize the RPV.

To resolve USI A-45, one of the alternatives proposed by the staff in NUREG-0933 was to have each licensee perform a risk assessment for its plant. The regulation in 10 CFR Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants," requires the design certification applicant to perform a risk assessment. The staff's evaluation of the ESBWR PRA is included in Section 19 of this report. The staff considers issue A-45 resolved, based on its evaluation in Section 19 of this report.

B-55: Improved Reliability of Target Rock Safety Relief Valves

As discussed in NUREG-0933, Issue B-55 addresses the failure of a pressure relief system valve to open on demand, which results in a decrease in the total available pressure-relieving capacity of the system. Similarly, spurious openings of pressure relief system valves, or failures of valves to properly reseal after opening, can result in inadvertent RCS blowdown with unnecessary thermal transients on the reactor vessel and the vessel internals, unnecessary hydrodynamic loading of the containment system's pressure suppression chamber (i.e., torus) and its internal components, and potential increases in the release of radioactivity to the environs. In addition, if the failed valve also serves as part of the automatic depressurization system (ADS), the ability of the ADS to perform its emergency core cooling function could be degraded.

In resolving the issue, the staff found that licensees had significantly improved the performance of Target Rock safety relief valves (SRVs) and were continuing to evaluate and improve their performance. Licensee compliance with existing regulations, such as Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50 and 10 CFR 50.65 was sufficient for the staff to pursue additional improvements on a plant-specific basis, if needed. Thus, the issue was resolved with no new or revised requirements.

In DCD Tier 2, Revision 9, Table 1.11-1, the applicant indicated that Issue B-55 was resolved with no new requirements. DCD Tier 2, Revision 9, Section 3.9.3.5 specifies that the qualification programs for valve designs that were developed for the ESBWR and were not previously qualified will meet the requirements of American Society of Mechanical Engineers (ASME) Standard QME-1-2007, "Qualification of Active Mechanical Equipment Used in Nuclear Power Plants." For valves that were previously qualified, the DCD specifies key features of lessons learned from nuclear power plant operations and research programs included in QME-1-2007 as part of its design specifications. For example, qualification specifications (e.g., design specifications) consistent with Appendix QV-I, "Qualification Specification for Active Valves," and Appendix QV-A, "Functional Specification for Active Valves for Nuclear Power Plants," to QME-1-2007 will be prepared for previously qualified valves to ensure operating conditions and safety functions for which the valves are to be qualified are communicated to the

manufacturer or qualification facility. Suppliers will submit, for GEH review and approval, application reports as described in QME-1-2007 that describe the basis for the application of specific predictive methods and/or qualification test data to a valve application. In September 2009, the NRC issued Revision 3 to Regulatory Guide (RG) 1.100, "Seismic Qualification of Electric and Active Mechanical Equipment and Functional Qualification of Active Mechanical Equipment for Nuclear Power Plants," which accepts the use of the QME-1-2007 standard, with certain staff positions, for the functional design and qualification of safety-related pumps, valves, and dynamic restraints.

DCD Tier 2, Revision 9, Section 3.9.3.5 provides additional qualification provisions for specific valve types, such as safety relief valves. As discussed in Section 3.9.6 of this SER, the staff considers the provisions in the DCD for functional design and qualification of valves to be acceptable for the ESBWR design certification in that the provisions incorporate the lessons learned from valve operating experience and research programs through application of the ASME QME-1-2007 standard for new valve qualification and key features of QME-1-2007 for previously qualified valves, where applied consistent with NRC acceptance of the standard in Revision 3 to RG 1.100. As described in DCD Tier 2, Revision 9, Section 14.2.8.1.1, valve operability is also verified during the pre-operational test program. The SRVs are tested in accordance with quality control procedures to detect defects and to provide operability before installation. Based on its evaluation of valve qualification in Section 3.9.6 and pre-operational testing in Section 14.2.3.1 of this report, the staff finds issue B-55 is resolved for the ESBWR design.

B-63: Isolation of Low Pressure Systems Connected to the Reactor Coolant Pressure Boundary

As discussed in NUREG-0933, Issue B-63 addresses the adequacy of the isolation of low-pressure systems that are connected to the RCPB. Design pressures in several systems connected to the RCPB in operating plants are considerably below the RCS operating pressure. The NRC has established acceptance criteria in SRP 3.9.6 to address the isolation of low pressure systems connected to the RCPB. The functional qualification and testing of pressure isolation valves (PIVs) are addressed in Section 3.9.6 of this SER. The staff finds this acceptable because PIVs to be used in the ESBWR satisfy SRP 3.9.6 for functional design, qualification, and inservice testing (IST).

C-1: Assurance of Continuous Long -Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment

This issue concerns the long-term capability of hermetically sealed instruments and equipment that must function in post-accident conditions. More specifically, certain classes of instrumentation that are equipped with seals are sensitive to steam and vapor. If the seals become defective as a result of personnel error during equipment maintenance, such errors could lead to the loss of a seal and of equipment functionality. The focus of this issue is to establish confidence that sensitive equipment has an effective seal for the lifetime of the plant. The review criterion for this issue is compliance with the review criteria of SRP Section 3.11 for environmental qualification of electrical equipment.

DCD Tier 2, Revision 9, Appendix 3H, defines the environmental conditions with respect to limiting design conditions for all safety-related mechanical and electrical equipment. Environmental conditions are tabulated by zones contained in the referenced building arrangements. Environmental conditions for the zones where safety-related equipment is

located are calculated for normal, abnormal, test, accident, and post-accident conditions and are documented in DCD Tier 2, Revision 9, Appendix 3H. The environmental qualification document includes a list of all safety-related electrical and mechanical equipment required for safe shutdown that is located in a harsh environment as stated in DCD Tier 2, Revision 9, Section 3.11.1.

Safety-related electrical equipment that is located in a harsh environment is required by 10 CFR 50.49(f) to be qualified by test or other methods, such as those described in Institute of Electrical and Electronic Engineers (IEEE) 323, "Qualifying Class 1E Equipment for Nuclear Power Generating Stations," dated 1974. The NRC-approved topical report, NEDE-24326-1-P, "General Electric Environmental Qualification Program," January, 1983, describes the qualification methodology in detail. This topical report also addresses compliance with the applicable portions of Appendix A to 10 CFR Part 50, and the quality assurance (QA) criteria of Appendix B to 10 CFR Part 50. Additionally, the report describes conformance to NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," issued November 1979, and the RGs and IEEE standards referenced in SRP Section 3.11. Details on the staff's evaluation of environmental qualification of safety-related electrical equipment are provided in Section 3.11 of this report. Based on the above discussion and the staff's evaluation in Section 3.11 of this report, the staff concludes that GEH has adequately addressed this issue for the ESBWR design.

C-11: Assessment of Failure and Reliability of Pumps and Valves

DCD Tier 2, Revision 9, Table 1.11-1, provides the resolution of task action plan Item C-11, "Assessment of Failure and Reliability of Pumps and Valves," for the ESBWR. In particular, GEH indicated that this item was generically resolved with no new requirements. The DCD Tier 2 addresses the design and performance of pumps and valves in several subsections. The staff discusses the functional design, qualification, and IST of pumps and valves in Section 3.9.6 of this report. DCD Tier 2, Revision 9, Section 3.9.6.2, "Inservice Testing of Pumps," notes that no pumps are included in the IST Program because the ESBWR design does not require the use of pumps to mitigate the consequences of any design basis accidents, or to achieve or maintain the safe shutdown condition. Because of the DCD provisions for valve design and qualification in accordance with ASME Standard QME-1-2007, and because combined license (COL) Information Item 3.9.9-3-A, "Inservice Testing Programs," requires COL applicants to provide a full description of the IST Program, the staff concludes that GEH has adequately addressed this issue in the ESBWR design.

20.3 New Generic Issues

This section addresses the staff's evaluation of USIs and generic safety issues (GSIs) that are categorized as "new generic issues" in NUREG-0933.

Issue 57: Effects of Fire Protection System Actuation on Safety-Related Equipment

As discussed in NUREG-0933, Issue 57 provides guidance on avoiding damage to required safety-related equipment due to fire suppression system discharge. DCD Tier 2, Revision 9, Appendix 9A, Section 9A.4 describes the design features to ensure that suppression system discharge will not prevent safe shutdown. The staff's evaluation of DCD Tier 2, Revision 9, Appendix 9A and Section 9A.4 can be found in Section 9.5.1 of this report. Based on its review in Section 9.5.1, the staff finds this GSI is resolved for the ESBWR design.

Issue 75: Generic Implications of ATWS Event at the Salem Nuclear Plant

As discussed in NUREG-0933, Issue 75 addresses the generic implications of two events at Salem Unit 1 where there were failures to scram automatically because of the failure of both reactor trip breakers to open upon receipt of an actuation signal. This issue was expanded to include a number of concerns raised by the staff that were closely related to the design and testing of the reactor protection system (RPS). The requirements for this issue were stated in GL 83-28, "Required Actions Based on Generic Implications of Salem ATWS Event," dated July 8, 1983.

In DCD Tier 2, Revision 9, Table 1.11, the applicant addresses this issue. The RPS designs for BWRs are substantially different from the reactor trip system design used in Salem Unit 1. DCD Tier 2, Revision 9, Sections 3.1.2.5 (and the preceding Sections 3.1.2.2 to 3.1.2.4) and Table 3.1 of NUREG-1000, Volume 1, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant," issued April 1983, describe the basic differences between BWR designs used at the time of the Salem events and the reactor trip system designs then used by PWRs.

The applicant maintains that the ESBWR further improves upon the BWR RPS designs used at the time of the Salem anticipated transient without scram (ATWS) events. The RPS is designed to provide a reliable single failure-proof capability to automatically or manually initiate a reactor scram while maintaining protection against unnecessary scrams resulting from a single-failure, even when bypassed and/or when one of the four automatic RPS trip logic systems is out-of-service. This is accomplished through the combination of fail-safe equipment design, the redundant two-out-of-four sensor channel trip decision logic, and the redundant two-out-of-four trip systems output scram logic arrangement utilized in the RPS design.

Staff's evaluation of the RPS system is included in Section 7 of this report. Based on its review of DCD Tier 2, Revision 9, Section 7.2.2, the staff finds that the ESBWR RPS design provides a reliable single-failure-proof capability to automatically or manually initiate a reactor scram while maintaining protection against unnecessary scrams resulting from single failures. The RPS is considered reliable because the RPS meets the requirements of 10 CFR 50.55a(h). The RPS remains single-failure-proof even when one entire division of channel sensors is out of service. Based on the above information and the staff's evaluation in Section 7 of this report, the staff finds that Issue 75 is resolved for the ESBWR design.

Issue 80: Pipe Break Effects on Control Rod Drive Hydraulic Lines in the Drywells of BWR Mark I and II Containments

In DCD Tier 2, Revision 9, Table 1.11, the applicant addresses this issue. Issue 80 as described in NUREG-0803, dated August 1981, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," does not apply to the ESBWR design. The ESBWR design does not include scram discharge volume piping. The water displaced by the control rod drive (CRD) during the scram in an ESBWR will be routed to the RPV.

Issue 105: Interfacing Systems LOCA at LWRs

GEH addresses its evaluation of this issue in DCD Tier 2, Revision 9, Appendix 3K. For advanced reactor designs, the staff stated its position regarding intersystem LOCA (ISLOCA) protection in SECY-90-016, "Evolutionary Light Water (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements," issued January 12, 1990, as well as in

SECY-93-087, "Policy, Technical Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs," issued April 2, 1993.

In SECY-90-016, the staff stated that designers of future ALWR plants should reduce the possibility of a LOCA outside containment by designing to the extent practicable all systems and subsystems connected to the RCS to an ultimate rupture strength (URS) at least equal to the full RCS pressure.

In SECY 93-087, the staff further indicated that enhancements of isolation capability or the number of inter-system barriers (e.g., three isolation valves) are not considered to be adequate alternatives in systems that can be practically designed to the URS criteria. For example, piping runs should be designed to meet the URS Criteria, as should all associated flanges, connectors, and packing, including valve stem seals, pump seals, heat exchanger tubes, valve bonnets, and RCS drain and vent lines. The staff further stated that the designer should also make every effort to minimize the pressure loading experienced by each system and subsystem connected to the RCS should an ISLOCA occur. The staff does recognize, however, that all systems must eventually interface with atmospheric pressure and that it would be difficult or prohibitively expensive to design certain large tanks and heat exchangers to an URS equal to normal RCS operating pressure. Applicants should provide justification demonstrating that it is not practicable to reduce the pressure challenge any further for each interfacing system and component that does not meet the RCS URS. This justification should be based upon an engineering feasibility analysis and not solely on the ratio of risk to benefit.

Accordingly, an applicant should demonstrate a compensating isolation capability for each interface for which it submits acceptable justification on the impracticability of normal RCS operating pressure capability. This would include a discussion of how the degree and quality of isolation or the reduced severity of the pressure challenges compensate for the low-pressure design of the interfacing system or component. The vendor may also need to consider the adequacy of pressure relief and piping of relief back to primary containment. In SECY-90-016, the staff stated that systems that have not been designed to full RCS pressure must include the following protection measures:

- (1) the capability for leak testing of the pressure isolation valves, (2) valve position indication that is available in the control room when isolation valve operators are de-energized, and (3) high-pressure alarms to warn control room operators when rising RCS pressure approaches the design pressure of the attached low -pressure systems and both isolation valves are not closed.

The following items form the basis of what constitutes practicality and set forth the test of practicality used to establish the boundary limits of URS for the ESBWR. GEH stated in DCD Tier 2, Revision 9, Appendix 3K that the design pressure for the low-pressure piping systems that interface with the RCS pressure boundary is equal to 0.4 times the normal reactor operating pressure of 7.07 megapascals (MPa) (1,025 pound per square inch gauge [psig]), that is, 2.83 MPa (410 psig) and the minimum wall thickness of the low-pressure piping should be no less than that of a standard weight pipe. The design of the piping is to be in accordance with Section III of the ASME Boiler & Pressure Vessel Code. Class 300 valves will be used for the interface systems. Furthermore, the staff will continue to require periodic surveillance and leak rate testing of the pressure isolation valves through technical specifications, as part of the ISI program.

The staff determined that a class 300 valve is adequate for ensuring the integrity of the low-pressure piping system under full reactor pressure. Non-piping components also will be designed to 2.83 MPa (410 psig). This is accomplished in the DCD, Tier 1, Revision 9 by the boundary symbols on system drawings. The boundary symbol on the system drawing applies to the piping and components that extend away from the boundary symbol, including along any branch line, until another boundary symbol occurs on the drawing. The components include flanges and pump seals.

The staff determined that it is impractical to construct large tank structures to the URS design pressure that are vented to the atmosphere and have a low design pressure. Also, it is considered impractical to upgrade the suppression pool and primary containment. The suppression pool provides a low-pressure sink and the ESBWR containment has a design pressure of 0.31 MPa (45 psig) and is designed to seismic Category I requirements. Based on the staff guidance described above, GEH evaluated, in DCD Tier 2, Revision 9, Appendix 3K, the following systems that interface with the RCS to verify that they are designed for an ISLOCA "to the extent practicable":

- CRD system
- SLCS
- RWCU/SDC system
- FAPCS
- Nuclear boiler system (NBS)
- Condensate & Feed water system

The pressure of each system piping boundary was reviewed to identify where changes were needed to provide the URS protection.

Based on the preceding information and its evaluation in Sections 3.12.6.19 and 3.12.3.6.20 of this report, the staff concludes that the ESBWR design meets the criteria of SECY-90-016 regarding ISLOCA prevention and mitigation.

Issue 106: Piping and the use of Highly Combustible Gases in Vital Areas

As discussed in NUREG-0933, this GSI provides guidance on systems and procedures for highly combustible gas used in vital areas of the plant. The staff included this GSI in its review of the ESBWR design as described in DCD Tier 2, Revision 9, Section 9.5.1, and evaluated GEH's design with respect to the design of systems and the use of highly combustible gases in vital areas. Section 9.5.1 of this report documents the staff evaluation. This subject is also addressed by resolution of GL 93-006 in Section 20.5.1 of this report. Based on its review discussed in Sections 9.5.1 and 20.5.1, the staff finds that this GSI is resolved for the ESBWR design.

Issue 189: Susceptibility of Ice Condenser and Mark III Containments to Early Failure from Hydrogen Combustion During a Severe Accident

In DCD Tier 2, Revision 9, Table 1.11, the applicant addresses this issue.

Prevention of hydrogen combustion in the ESBWR containment is achieved by using an inerted containment in accordance with 10 CFR 50.44(c)(2). This issue is resolved for the ESBWR design

Issue 193: BWR ECCS Suction Concerns

GSI-193 addresses the possibility of air intrusion into the emergency core cooling system (ECCS) suction piping and the possible degradation of the ECCS pumps as the result of cavitation. Since the ESBWR does not have ECCS pumps, the staff finds that this GSI is not applicable to ESBWR. However the staff recognizes that there are effects on ECCS systems due to air intrusion. Non-condensable gas (i.e. air) might enter the PCCS and degrade its performance. The PCCS helps to suppress pressure increase in the drywell as well as supply liquid inventory to the reactor vessel during long-term core cooling. Sections 6.2 and 6.3 of this report describe the staff's evaluation of possible air intrusion in the PCCS and its effects on containment pressure suppression and long-term core cooling, respectively. As discussed in Sections 6.2 and 6.3 of this report, the staff considers Issue 193 resolved for the ESBWR design. In addition, the FAPCS provides non-safety related RTNSS functions of suppression pool cooling and low pressure coolant injection which provide defense-in-depth to the ESBWR ECCS functions. Section 9.1.3.3 of this report evaluates the applicant's design features and controls to prevent and mitigate gas intrusion into the FAPCS.

20.4 Three Mile Island (TMI) Action Plan Items

This section addresses the staff's evaluation of GSIs that are categorized as "TMI action plan items" in NUREG-0933 and TMI requirements found in 10 CFR 50.34(f).

I.C.5: Procedures for Feedback of Operating Experience to Plant Staff

The regulation in 10 CFR 50.34(f)(3)(i) requires the provision of administrative procedures for evaluating operating, design, and construction experience and for ensuring that applicable important industry experiences will be provided in a timely manner to those designing and constructing the plant. According to DCD Tier 2, Revision 9, Chapter 1, Appendix 1A, Table 1A-1, the ESBWR design engineers are continually involved in reviewing industry experience from sources such as NRC BLs, licensee event reports, NRC request for information letters to holders of operating licenses, *Federal Register* information, and GLs. GEH made a commitment to address these procedures in DCD Tier 2, Sections, 13.2.3, 13.5.2 and 18.3. The staff's evaluation of this commitment appears in Sections 13.2.3, 13.5.2, and 18.3 of this report. Based on its review in Sections 13.2.3, 13.5.2 and 18.3, the staff finds that TMI Action Item I.C.5 is resolved for the ESBWR design.

I.C.9: Long-Term Program Plan for Upgrading of Procedures

The regulation in 10 CFR 50.34(f)(2)(ii) requires establishment of a program, to begin during construction and follow into operation, for integrating and expanding current efforts to improve plant procedure. DCD Tier 2, Revision 9, Chapter 1, Appendix 1A, Table 1A-1, addresses this issue and references DCD Tier 2, Revision 9, Section 13.5. GEH addresses procedures in DCD Tier 2, Sections 13.5, 18.9, and in the topical report "ESBWR Human Factors Engineering Procedures Development Implementation Plan" issued February 2010 (NEDO-33274). The staff's evaluation appears in Sections 13.5 and 18.9 of this report. Based on its review in Sections 13.5 and 18.9, the staff finds that TMI Action Item I.C.9 is resolved for the ESBWR design.

I.F.1: Expand QA List

As required by 10 CFR 52.47(a)(8), an applicant for design certification must demonstrate compliance with any technically relevant portions of the TMI requirements in 10 CFR 50.34(f). As required by 10 CFR 50.34(f)(3)(ii), an application must provide sufficient information to “ensure that the quality assurance (QA) list required by Criterion II, Appendix B, 10 CFR Part 50 includes all structures, systems, and components important to safety (I.F.1).” This requirement was intended to expand the QA list to ensure that non-safety-related SSCs that are important to safety are subject to appropriate QA controls.

The staff reviewed the QA controls described in the DCD Tier 2, Revision 9, Sections 17.4 and 17.5 that are applicable to the non-safety-related SSCs to verify that adequate controls are specified to ensure the reliability and availability of risk-significant, non-safety-related SSCs. The staff determined that alternate quality assurance programs, such as the reliability assurance program and the RTNSS, are sufficient to provide reasonable assurance that non-safety-related SSCs that are important to safety will perform satisfactorily in service. Section 17.4 of this report discusses the staff’s evaluation of the ESBWR reliability assurance program. Based on the existence of alternate quality programs that provide reasonable assurance that non-safety-related SSCs important to safety will perform satisfactorily in service, the staff concludes that the DCD meets the requirements of 10 CFR 50.34(f)(3)(ii). The staff finds that GEH has adequately addressed this TMI requirement.

Issue I.F.2: Develop More Detailed QA Criteria

As required by 10 CFR 52.47(a)(8), an applicant for design certification must demonstrate compliance with any technically relevant portions of the TMI requirements set forth in 10 CFR 50.34(f). As stated in 10 CFR 50.34(f)(3)(iii), an application must provide sufficient information to demonstrate that the applicant has established a QA program that considers the following:

(A) ensuring independence of the organization performing checking functions from the organization responsible for performing the functions; (B) performing quality assurance/quality control functions at construction sites to the maximum feasible extent; (C) including QA personnel in the documented review of and concurrence in quality related procedures associated with the design, construction and installation; (D) establishing criteria for determining QA programmatic requirements; (E) establishing qualification requirements for QA and QC personnel; (F) sizing the QA staff commensurate with its duties and responsibilities; (G) establishing procedures for maintenance of “as built” documentation; and (H) providing a QA role in design and analysis activities.

The requirements in 10 CFR 50.34(f)(3)(iii) are intended to improve the QA program to provide greater assurance that plant design, construction, and operational activities are conducted in a manner commensurate with their importance to safety. The staff reviewed the requirements of 10 CFR 50.34(f)(3)(iii) to determine which requirements were technically relevant to a design certification applicant. The staff found that the requirements contained in 10 CFR 50.34(f)(3)(iii)(B), (D), and (E) pertain to QA activities during plant construction and operation, and therefore, were not technically relevant to a design certification applicant. Similarly, the requirements of 10 CFR 50.34(f)(3)(iii)(G) are associated with control of “as-built” documentation and, therefore, are not technically relevant to design certification. However, the staff found that 10 CFR 50.34(f)(3)(iii), Items A, C, F, and H are technically relevant to the design certification.

As required by 10 CFR 52.47(a)(21), an application for design certification must contain proposed technical resolutions of those medium- and high-priority GSIs that are identified in the version of NUREG–0933, current on the date 6 months prior to the docket date of application and that are technically relevant to the design. The intent of I.F.2 was to improve the QA program for design, construction, and operations to provide greater assurance that plant design, construction, and operational activities were conducted in a manner commensurate with their importance to safety. Item I.F.2 was to provide more explicit and detailed criteria concerning the elements that were found in a well-conducted QA programs. As discussed in NUREG–0933, the staff resolved four issues associated with Item I.F.2 by establishing new requirements in SRP Chapter 17 to reflect the four relevant sections of 10 CFR 50.34(f)(3)(iii). These issues include the following:

- (1) Item I.F.2(2)–Include QA personnel in review and approval of plant procedures;
- (2) Item I.F.2(3)–Include QA personnel in all design, construction, installation, testing, and operation activities;
- (3) Item I.F.2(6)–Increase the size of the QA staff; and
- (4) Item I.F.2(9)–Clarify organizational reporting levels for the QA organization.

In DCD Tier 2, Revision 9, Appendix 1A, the applicant stated that the ESBWR QA plan described in DCD Tier 2, Revision 9, Section 17, meets the requirements of 10 CFR 50.34(f)(3)(iii) as they apply to the design of the ESBWR. Most requirements in 10 CFR 50.34(f)(3)(iii) overlap with the requirements in 10 CFR Part 50, Appendix B. However, some 10 CFR 50.34(f)(iii), Item I.F.2 requirements go beyond the requirements of Appendix B and are implemented separately.

As discussed above, the four new sections of NUREG–0933 cover the requirements in 10 CFR 50.34(f)(3)(iii)(A), (C), (F) and (H). NUREG–0933 classifies the remainder of the issues associated with Item I.F.2 as low-priority issues that the design certification applicant is not required to address. The staff concluded that because Items I.F.2(2), (3), (6), and (9) were resolved by a revision to SRP Chapter 17 in NUREG–0800, a review of the QA program conducted in accordance with SRP Section 17.3 would verify compliance with these requirements. The staff's evaluation of GEH's QA program is provided in Chapter 17 of this report. As stated in Section 17.1.3 of this report, the staff conducted three inspections to verify GEH's implementation of their QA program for the ESBWR design certification. During these inspections, the staff also verified that the requirements of 10 CFR 50.34(f)(3)(iii), identified as Items I.F.2(2), (3), (6), and (9) above, were implemented for the activities related to the ESBWR design certification. Issue I.F.2 is resolved for the ESBWR design because the requirements in 10 CFR 50.34(f)(3)(iii), 10 CFR 52.479(a)(8), and 10 CFR 52.47(a)(21) are met.

II.J.3.1: Organization and Staffing to Oversee Design and Construction

The regulation in 10 CFR 50.34(f)(3)(vii) requires the applicant to provide a description of the management plan for design and construction activities that includes the following:

- The organizational and management structure singularly responsible for direction of design and construction of the proposed plant
- Technical resources directed by the applicant

- Details of the interaction of design and construction within the applicant's organization and the manner by which the applicant will ensure close integration of the architect engineer and the nuclear steam supply vendor
- Proposed procedures for handling the transition to operation
- The degree of top-level management oversight and technical control to be exercised by the applicant during design and construction, including the preparation and implementation of procedures necessary to guide the effort.

In DCD Tier 2, Revision 9, Appendix 1A, Table 1A-1, GEH states that the ESBWR design team has developed a management plan for the ESBWR project which consists of a properly structured organization with open lines of communication, clearly defined responsibilities, and well-coordinated technical efforts, and appropriate control channels. GEH further stated in Table 1A-1 that the procedures to be used in the construction and operation phases of the plant are discussed in DCD Tier 2, Revision 9, Section 13.5 and the startup procedures are discussed in DCD Tier 2, Revision 9, Section 14.2. Sections 13.5 and 14.2 of this report present the staff's evaluation of these procedures. Based on its review in Sections 13.5 and 14.2, the staff finds that TMI Action Item II.J.3.1 is resolved for the ESBWR design.

II.K.1(22): Describe Automatic and Manual Actions for Proper Functioning of Auxiliary Heat Removal Systems When Feed Water Not Operable

The language of 10 CFR 50.34(f)(2)(xxi) requires incorporation of TMI-2 Action Item II.K.1(22) in a new plant design. In particular, auxiliary heat removal systems are to be designed such that necessary automatic and manual actions can be taken to ensure proper functioning when the main feedwater system is not operable.

The applicant stated in DCD Tier 2, Revision 9, Table 1A-1 that no short-term manual actions are necessary during loss of the feedwater system. Sufficient systems exist to automatically mitigate the consequences of a loss of feedwater event. DCD Chapter 15, Tier 2, describes an analysis performed for a loss-of-feedwater event. If the main feedwater system is not operable, a reactor scram and initiation of the ICS will occur because either (1) a detected Loss of All Feedwater occurred, or (2) the reactor water level fell as a result of void collapse, boil-off, and absence of makeup water. When reactor vessel water Level 3 is reached, a reactor scram is automatically initiated. Reactor water level continues to decrease because of void collapse and boil-off until the low-low level set point (Level 2) is reached. At this point, reactor isolation also occurs, but with a time delay for the MSIVs. When ICs receive an initiation signal, the condensate return valves will open in 30 seconds, placing the ICS in full operation, at which time the water level stabilizes. (High pressure CRD makeup, if available, will prevent the water level from falling to a point where ADS and GDCS are initiated. If the reactor pressure is low, the low-pressure coolant injection [LPCI] mode of the FAPCS also can be used to maintain the RPV level). If the ICs are not operable, the SRVs will open on high vessel pressure approximately 5 minutes later. The SRVs open and close to maintain vessel pressure. When the reactor vessel water level reaches Level 1 (at this level, MSIVs close immediately, if not already closed), an ADS timer is initiated. When the ADS timer is timed out, the ADS and SLCS system actuation sequence is initiated, and the GDCS timer is initiated. When the GDCS timer is timed out, the GDCS injection valves open. Vessel pressure then decreases below the static head of GDCS, and the GDCS reflooding flow into the vessel begins. The core remains covered throughout the sequence of events, and no core heatup occurs.

The staff reviewed the applicant's description above. The staff's evaluation of "Loss of feedwater flow" is described in Section 15.2.5.3 of this report. The staff noted that the ESBWR design incorporates appropriate automatic and manual action capability to ensure proper heat removal when the main feedwater system is not operable. Based on the information above and its evaluation in Section 15.2.5.3 of this report, the staff concludes that GEH has adequately addressed the requirements of this TMI-2 action item for the ESBWR design.

II.K.3(13): Separation HPCI and RCIC System initiation Levels Such that RCIC Initiation at a higher water level than HPCI/HPCS

The ESBWR is a passive plant and has no high-pressure coolant injection (HPCI), high-pressure core spray (HPCS), or reactor core isolation cooling (RCIC) systems. Therefore, TMI Action Item II.K.3(13) is not applicable to the ESBWR design. The staff concludes that this TMI Action Item II.K.3(13) is resolved for the ESBWR design.

II.K.3(28): Study and Verify Qualification of Accumulators on ADS Valves

The Applicant is required by 10 CFR 50.34(f)(1)(x), to perform a study to ensure that the ADS, valves, accumulators, and associated equipment and instrumentation will be capable of performing their intended functions during and following an accident situation. The study must give no credit for non-safety-related equipment or instrumentation, and must account for normal expected air (or nitrogen) leakage through valves. In DCD Tier 2, Revision 9, Table 1A-1, GEH discussed the resolution of this issue, also referred to as TMI Action Plan Item II.K.3(28).

In particular, GEH stated that the ESBWR ADS is made up of SRVs and squib-activated DPVs to depressurize the reactor. Following their actuation, the DPVs will not reclose until being refurbished. Each of the ADS SRVs is equipped with a pneumatic accumulator and check valve for the ADS, and manual opening functions. These accumulators ensure that the valves can be opened following failure of the gas supply to the accumulators. The accumulator capacity is sufficient for one actuation at drywell design pressure. The valves have been designed to achieve the maximum practical number of actuations consistent with state-of-the-art technology.

The DPVs are of a non-leak, non-simmer, non-maintenance design. They are straight-through, squib-actuated, non-reclosing valves with a metal diaphragm seal. The SRVs and DPVs, and their associated controls and actuation circuits, are located or protected so that their function cannot be impaired by the consequences of accidents. ADS components are qualified to withstand the harsh environments postulated for design basis accidents inside the containment, including high temperature, high pressure and high radiation environments as shown in DCD Section 3.11, Table 3.11-1. DCD Tier 2, Revision 9, Table 1A-1 refers the reader to Sections 5.2.2.2, 6.3.2.8, and 7.3.1.1 of the DCD for additional information. The staff discusses the SRVs and DPVs in Section 3.9.6 of this report. Based on its review in Section 3.9.6 of this report, the staff concludes that GEH has adequately addressed the requirements of TMI Action Item II.K.(3)28.

III.D.1.1: Primary Coolant Sources Outside the Containment

The regulation in 10 CFR 50.34(f)(2)(xxvi) requires the provision of leakage control and detection in the design of systems outside of containment that contain (or might contain) accident source term radioactive materials following an accident. Applicants are required to submit a leakage control program, including initial test program, a schedule for retesting these systems, and the actions to be taken to minimize leakage from such systems. The goals are to minimize potential

exposures to workers and the public and to provide assurance that excessive leakage will not prevent the use of systems needed in an emergency. In Revision 3 of the DCD, GEH cited two means of satisfying the requirements of 10 CFR 50.34(f)(2)(xxvi). In DCD Tier 2, Table 1A-1, GEH listed Appendix J testing and the Leak Detection and Isolation System (LD&IS) as a means to satisfy issue III.D.1.1. In RAI 20-12, the staff indicated that the Appendix J testing program and LD&IS have little bearing on issue III.D.1.1 and do not satisfy the 10 CFR 50.34(f)(2)(xxvi) requirements. The staff requested that GEH address Issue III.D.1.1 without relying on Appendix J testing and the LD&IS. In response to RAI 20.0-12, the applicant agreed that it should revise the response to TMI Action Plan Item III.D.1.1 to address detecting and limiting system leakage during plant operation. GEH indicated that it would accomplish this by defining a program to reduce leakage to as-low-as practical levels for all required post accident systems outside of containment that could contain highly radioactive fluid. GEH defined the program in Revision 4, DCD Tier 2, Table 1A-1. In this revision of Table 1A-1 it identified the ICS, FAPCS, and containment monitoring system (CMS) systems outside containment that contain or might contain source term radioactive materials following an accident.

However, after further review of Revision 4 of the DCD, the staff raised a concern as to whether GEH had identified all of the appropriate systems outside of containment that may contain source term radioactive materials following an accident. In RAI 20.0-16, the staff asked GEH to describe and justify the screening process used to determine which systems should be leak tested and meet the criteria described in the clarification section in NUREG-0737, "Clarification of TMI Action Plan Requirements," issued November 1980 for TMI III.D.1.1. The staff also requested that GEH identify the systems that require leak testing and justify the leak testing it proposed to perform for systems included under this item.

In response to RAI 20.0-16, the applicant indicated that the clarification section of NUREG-0737 for TMI Item III.D.1.1 provides a detailed list of systems that should be leak tested. The applicant further explained that during the preparation of the response to RAI 20.0-12, it reviewed the detailed list of systems and functions from the clarification section of NUREG-0737 and identified the corresponding ESBWR systems. As stated in its response to RAI 20.0-12 ICS, FAPCS, and CMS are the systems requiring leak testing. The applicant also indicated in its response to RAI 20.0-16 that it added the RWCU/SDC system to the list as a result of a design change to improve the post-LOCA reduction in containment pressure.

The applicant further explained that the screening process used to develop the list of systems consisted of reviewing the list of systems mentioned in the clarification section of NUREG-0737 for TMI Item III.D.1.1 and identifying the comparable ESBWR systems used to perform those design functions. In the response, GEH included a table showing how the systems in the TMI Item III.D.1.1 compare to the ESBWR design. GEH identified the systems that contain radioactive materials that are excluded from the program and discussed the justification for the exclusion in their response. GEH indicated that the NBS (the main steam and feedwater) contains radioactive materials during normal operations, but is automatically isolated during severe transients and accidents. Therefore, the NBS is not included on the list of systems requiring leak testing under TMI Item III.D.1.1. GEH also identified the offgas system as another system that contains radioactive materials during normal operation but is excluded from the list of systems requiring leak testing. GEH indicated that, historically the offgas system has been excluded from periodic leak testing for BWRs. GEH further explained that the offgas system has a design pressure of around 2.4 MPa gauge (350 psig), and is isolated from the RPV during serious transients and accidents after MSIV closure occurs. GEH also indicated in its response that ESBWR technical specifications, DCD Tier 2, Chapter 16, Section 5.5.2 implements the program for minimizing leakage from the systems identified. Staff finds GEH

response to RAI 20.0-16 acceptable because the applicant explained their screening process and identified all the appropriate systems in the ESBWR design that should be leak tested and meet the criteria described in the clarification section in NUREG-0737.

SRP Sections 12.3 and 12.4 state that the applicant should provide a dose assessment of major functions such as operations, radwaste handling, normal maintenance, special maintenance, refueling, and inservice inspection in accordance with the provisions of RG 8.19, "Occupational Radiation Dose Assessment in Light Water Reactor Power Plants Design Stage Person-Sievert Estimates," dated June 1979. Accordingly, the staff issued RAI 20.0-16 S01, requesting GEH to provide a listing of the estimated collected doses associated with the leak testing program and to verify that the dose assessment described in DCD Tier 2, Section 12.4 accounts for the occupational radiation exposures associated with the leak testing program. In response to RAI 20.0-16, S01, the applicant stated that Tables 12.4-2, 12.4-3, 12.4-4, 12.4-6, and 12.4-7 in DCD Tier 2, Section 12.4 already contain the occupational doses associated with the inspection of the systems and the leak test program. The staff found the response to RAI 20.0-16 S01, acceptable because tables in DCD Tier 2, Section 12.4 accounted for the occupational radiation exposures associated with the leak test program. Therefore, the staff concludes that GEH has adequately addressed TMI Action Item III.D.1.1 for the ESBWR design.

20.5 Operating Experience

This section addresses the staff's evaluation of the applicant's incorporation of operating experience insights into the design.

20.5.1 Generic Letters

GL 81-20, "Safety Concerns Associated with Pipe Breaks in the BWR Scram System," April 10, 1981

This GL is not applicable to the ESBWR design.

GL 81-37, "ODYN Code Re-analysis Requirements," December 29, 1981

DCD Tier 2, Revision 9, Table 1C-1, addresses this Issue.

This GL requires all BWR licensees to reanalyze the limiting transients with the OLYN code. GEH analyzes the transients in ESBWR using the TRACG04 code. This code supersedes the OLYN code and therefore, the staff finds GL 81-37 is not applicable to the ESBWR design.

GL 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," July 8, 1983

DCD Tier 2, Revision 9, Table 1C-1, addresses this Issue. Based on information in NUREG-1000, the staff identified actions to be taken by applicants as a result of the Salem ATWS events. These actions addressed issues related to reactor trip system reliability and general management capability. The actions covered by this letter fall into the following four areas:

- (1) Post-Trip Review—This action addresses the program, procedures, and data collection capability to ensure that the causes for unscheduled reactor shutdowns, as well as the response of safety-related equipment, are fully understood before plant restart.

- (2) **Equipment Classification and Vendor Interface**—This action addresses the programs for ensuring that all components necessary for accomplishing required safety-related functions are properly identified in documents, procedures, and information-handling systems that are used to control safety-related plant activities. In addition, this action addresses the establishment and maintenance of a program to ensure that vendor information for safety-related components is complete.
- (3) **Post maintenance Testing**—This action addresses post-maintenance operability testing of safety-related components.
- (4) **Reactor Trip System Reliability Improvements**—This action is aimed at ensuring that vendor-recommended reactor trip breaker modifications and associated RPS changes are completed in PWRs, that a comprehensive program of preventive maintenance and surveillance testing is implemented for the reactor trip breakers in PWRs, that the shunt trip attachment activates automatically in all PWRs that use circuit breakers in their reactor trip system, and to ensure that on-line functional testing of the reactor trip system is performed on all LWRs.

As discussed in the staff evaluation of Generic Issue 75 in Section 20.3 of this report, the staff concludes that this issue is resolved.

GL 83-33, “NRC Position on Certain Requirements of Appendix R to 10 CFR Part 50,” October 19, 1983

This GL was superseded by GL 86-10. For more information, refer to staff’s evaluation of GL 86-10 later in this section.

GL 84-23, “Reactor Vessel Water Level Instrumentation in BWRs,” October 26, 1984

DCD Tier 2, Revision 9, Table 1C-1, addresses this issue.

This GL identifies the following potential improvement categories for the operating reactors:

- Improvements to plant(s) that will reduce level indication errors caused by high drywell temperature. These improvements include prevention of reference leg overheating or reduction of the vertical drops in the drywell. (Vertical drop should be measured from the condensation pot to the drywell exit point. Maximum drop would allow an indicated level at the bottom of the normal operating range when the actual level is just above lower tap for worst flashing condition.) Those plants for which the vertical drop in the drywell has already been minimized will not have to make additional changes for the drywell heating effect.
- Review of plant experience relating to mechanical level indication equipment. Plant experience shows mechanical level equipment is more vulnerable to failure or malfunction than analog equipment. A number of plants have already connected analog trip units to their level transmitters to improve reliability and accuracy. Those plants that use mechanical level indication should replace the mechanical level indication equipment with analog level transmitters unless operating experience confirms high reliability.
- Changes to the protection system logic that may be needed for those plants in which operator action may be required to mitigate the consequences of a break in a reference leg

and a single failure in a protection system channel associated with an intact reference leg. Changes will generally result in additional transmitters to satisfy the single failure criterion.

The staff reviewed the ESBWR design for the reactor vessel water level measurement system requirements specified in GL 84-23. In RAI 20.0-7, the staff stated that confirmation was needed regarding the adequacy of the differential pressure method for the RPV level measurement, and asked the applicant to explain in detail the systems design, operation, and operator actions during transients, and demonstrate that the RPV level system was robust. In response to RAI 20.0-7, the applicant submitted additional information about the RPV level measurement system. The applicant stated that in the ESBWR design, the direct RPV water level measurement instrumentation system detects conditions of adequate core cooling. The RPV water level is the primary variable in the BWR for indicating the availability of adequate core cooling. Four independent divisions of differential pressure sensing instruments provide water level sensing. They are designed to be adequately redundant and unambiguous so that ESBWR level indication is accurate and reliable. Each division of level sensing instruments includes a differential pressure instrument for one of four measurement regions including fuel zone, wide range, narrow range (primarily used for power operation level indication and feedwater control logic), and shutdown range (used during refuel operations). Each division has its own set of RPV sensing line nozzle connections. RAI 20.0-7 was resolved because the ESBWR has addressed the issue of false high water level indication upon vessel depressurization or as the result of events that cause vessel pressure reduction transients. The ESBWR design has an instrument line vertical drop in conformance with the guidelines in RG 1.151, "Instrument Sensing Lines," dated July 1983.

The staff concludes that when implemented in the ESBWR, these improvements will increase assurance that the level instrumentation will detect inadequate core cooling, as specified in NUREG-0737, Item II.F.2, and thereby satisfy this requirement. Section 7.1.1.3.4 of this report presents the staff evaluation of TMI-2 Action Item II.F.2. Based on the staff's evaluation of Item II.F.2, the staff considers this GL resolved for the ESBWR design.

GL 85-01, "Fire Protection Policy Steering Committee Report," January 9, 1985

The NRC never formally issued this GL. The content of the draft version of GL 85-01 subsequently became GL 86-10, which is addressed below. Therefore, the staff considers this GL resolved for the ESBWR design.

GL86-10, "Implementation of Fire Protection Requirements," April 24 1986

This GL applies to existing plants licensed before January 1, 1979. SRP Section 9.5.1 and RG 1.189, "Fire Protection for Nuclear Power Plants," dated March 2007 provide the corresponding guidance for new reactors. Section 9.5.1 of this report addresses the staff evaluation of the applicant's compliance with the fire protection requirements. Therefore, based on the staff's evaluation in Section 9.5.1 of this report, the staff considers this GL is resolved for the ESBWR design.

Supplement 1 to GL 86-10, "Fire Endurance Test Acceptance Criteria for Fire Barrier Systems Used to Separate Redundant Safe Shutdown Trains Within the Same Fire Area," March 25, 1994

This supplement provides guidance on the qualification testing of fire barrier systems. RG 1.189 includes the guidance provided by this supplement. However, the DCD does not

identify any applications for these systems. Any proposed use of such systems will be identified by the applicant and the design evaluated by the staff during the review of the COL application in response to COL Information Item 9.5.1-5-A. Therefore, the staff considers this GL resolved for the ESBWR design.

**GL 87-06, “Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves,”
March 13 1987**

DCD Tier 2, Revision 9, Table 1C-1 indicates that GL 87-06, does not apply to the ESBWR. In its response to RAI 20.0-11, the applicant stated that the basis for this statement is provided in DCD Tier 2, Revision 9, Appendix 3K, Section 3K.2, which specifies that the periodic surveillance and leak rate testing requirements for high-pressure to low-pressure isolation valves do not apply to the ESBWR, because the ESBWR design does not contain a pressure isolation valve between the RCPB and a low pressure piping system. GEH stated that it would revise Table 1C-1 to reference DCD Tier 2, Appendix 3K, to support the statement that the GL is not applicable to the ESBWR. As a result, DCD Tier 2, Revision 6, Table 1C-1 references Appendix 3K in an acceptable manner. Therefore, RAI 20.0-11 is resolved. The staff considers this GL resolved for the ESBWR design.

GL 88-18, “Plant Record Storage on Optical Disks,” October 20, 1988

The purpose of GL 88-18 is to inform all licensees that the staff approves the use of plant record storage on optical disks for record keeping when appropriate QA controls are applied. In DCD Tier 2, Appendix 1C, the applicant stated that it is the responsibility of the COL applicant and licensee to supplement DCD Subsection 17.1.17, which states that the topical report GEH “QA Program Description,” issued March 1989 (NEDO-11209-04A) establishes control requirements of QA records used during the design of the ESBWR. The staff agrees that NEDO-11209-04A establishes control requirements for QA records and that the COL applicant and licensee will also need to establish control requirements for QA records consistent with the guidance in GL 88-18, if applicable. This will be addressed by COL Information Items 17.2-1-A, 17.2-2-A, 17.3-1-A. Therefore, the staff considers this GL resolved for the ESBWR design because COL applicants will address this GL.

GL 89-02, “Actions To Improve the Detection of Counterfeit and Fraudulently Marketed Products,” March 21, 1989

The purpose of GL 89-02 is to share with all licensees some of the elements of programs that appear to be effective in detecting counterfeit or fraudulently marketed products and in ensuring the quality of vendor products.

In DCD Tier 2, Appendix 1C, the applicant stated that it is the COL applicant and the licensee’s responsibility to address the guidance of GL 89-02. The staff agrees with the applicant that GL 89-02 is not applicable to the DCD review. This is a procurement issue related to components, which is the responsibility of the COL applicant and licensee. COL applicants will consider GL 89-02 when addressing COL Information Items 17.2-1-A, 17.2-2-A and 17.3-1-A. The staff considers this GL resolved for the ESBWR design because it will be addressed by these COL information items in DCD Tier 2, Revision 9, Sections 17.2 and 17.3.

GL 89-04, “Guidance on Developing Acceptable IST Programs,” April 3, 1989

The staff issued GL 89-04, and its Supplement 1 to provide information for nuclear power plant licensees to use in satisfying the NRC regulations for IST programs. In response to RAI 20.0-9, the applicant stated that DCD Tier 2, Appendix 1C, “Industry Operating Experience,” would be revised to clarify the GLs and BLs within the scope of the COL application. In DCD Tier 2, Revision 6, Table 1C-1, the applicant listed GL 89-04 and its Supplement 1 for consideration by the COL applicant, and referred to DCD Tier 2, Section 3.9.6, to address the issues in the GL. The staff considers the reference in Table 1C-1 to the appropriate DCD section for GL 89-04 for consideration by the COL applicant as specified in COL Information Item 3.9.9-3-A, to be acceptable because the staff has revised SRP Section 3.9.6 to update the guidance for staff’s review of IST programs described by design certification and COL applicants, and to incorporate lessons learned from GL 89-04 and other applicable GLs that address nuclear power plant operating experience. Therefore, RAI 20.0-9 is closed. The staff considers this GL resolved for the ESBWR design.

GL 89-18, “Resolution of Unresolved Safety Issue A-17, ‘System Interactions in Nuclear Power Plants,’” September 6, 1989

The discussion of task action plan Item A-17 is addressed in Section 20.2 of this report. Based on the staff’s evaluation of USI A-17 in Section 20.2 of this report, the staff concludes that this GL is resolved.

GL 91-05, “Licensee Commercial-Grade Procurement and Dedication Programs,” April 9, 1991

The purpose of GL 91-05 is to allow licensees sufficient time to fully understand and implement guidance developed by industry to improve procurement and commercial grade dedication programs. In DCD Tier 2, Appendix 1C, the applicant stated that it is the responsibility of the licensee to address the guidance of GL 91-05.

The staff agrees with the applicant that GL 91-05 does not apply to the DCD review because this is a procurement issue, and GEH is not procuring any commercial grade items as part of the design certification. The licensee is responsible for procurement issues, which may include commercial grade dedication. GL 91-05 will be addressed by COL Information Items 17.2-1-A, 17.2-2-A and 17.3-1-A. Therefore, the staff considers this GL resolved for the ESBWR design because it will be addressed by the COL applicants.

GL 91-16, “Licensed Operators’ and Other Nuclear Facility Personnel Fitness for Duty,” October 3, 1991

GL 91-016 does not apply to the DCD review because the subject matter of GL 91-016, the fitness-for-duty of licensed operators and other nuclear facility personnel is not relevant to DCs.

GL 92-04, “Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f),” August 19, 1992

DCD Tier 2, Revision 9, Table 1C-1, addresses this issue. The NRC issued the GL 92-04 to request information regarding the adequacy of and corrective actions for BWR water level instrumentation with respect to the effects of noncondensable gases on system operation. As discussed in NRC IN No. 92-54 “Level Instrumentation Inaccuracies Caused by Rapid

Depressurization,” dated July 24, 1992, the staff was concerned that noncondensable gases may become dissolved in the reference leg of BWR water level instrumentation and lead to a false high level indication after a rapid depressurization event. The dissolved gases, which accumulate over time during normal operation, can rapidly come out of solution during depressurization and displace water from the reference leg. A reduced reference leg level will result in a false indication of a high level. This is important to safety because water level signals are used for actuating automatic safety systems and to guide operators during and after an event.

The staff later issued BL 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in BWRs," dated May 28, 1993, requesting hardware modifications for operating reactors. As described in DCD Tier 2, Revision 9, Section 7.7.1.2.2, GEH incorporated a backfill modification system that will constantly purge the reference leg with a very low flow rate of water supplied by the CRD system. The constant flow of water up the reference leg will prevent dissolved gases from migrating down the reference leg. The ESBWR RPV level instrumentation system design incorporates the modifications recommended by the staff and the staff finds that the design addresses the concerns identified in GL 92-04 and BL 93-03. The staff concludes that this GL is resolved for the ESBWR design.

GL 92-08, “Thermo-Lag 330-1 Fire Barriers,” December 17, 1992 (BL 92-001)

This GL provided information on testing performed to determine the fire endurance capability of Thermo-Lag 330-1 fire barriers. The DCD does not identify any applications for this type of fire barrier system. Any proposed use of such systems will be identified by COL applicants and the design evaluated by the staff at the COL application stage in response to COL Information Item 9.5.1-5-A. Therefore, this GL is resolved for the ESBWR design.

GL 93-06, “Research Results on Generic Safety Issue 106, Piping and the Use of Highly Combustible Gases in Vital Areas,” October 25, 1993

This GL provides guidance on meeting GSI 106. The staff included GL 93-06 in its review of the ESBWR design and evaluated the GEH design with respect to the use of highly combustible gases in vital areas. DCD Tier 2, Revision 9, Table 9A.5-1 provides the locations and amounts of highly combustible gases, and describes safety features used in the ESBWR design to contain and mitigate a potential explosion and fire in areas with highly combustible gases. The staff finds that the elements of the ESBWR design that contain and mitigate the hazards of highly combustible gases, as described in the ESBWR fire hazards analysis in DCD Tier 2, Revision 9, Appendix 9A, are adequate. The staff’s review of the ESBWR fire hazards analysis is provided in Section 9.5.1 of this report. Based on the information above and the staff’s evaluation in Section 9.5.1, the staff considers this GL resolved for the ESBWR design.

GL 2006-03, “Potentially Nonconforming Hemyc and MT Fire Barrier Configurations,” April 10, 2006

The DCD does not identify any applications for this type of fire barrier system. Any proposed use of such systems will be identified by the applicant and the design evaluated by the staff at the COL application stage. Therefore the staff considers this GL resolved for the ESBWR design.

20.5.2 Bulletins

BL 80-01, “Operability of ADS Valve Pneumatic Supply,” January 11, 1980

In DCD Tier 2, Revision 9, Table 1C-2, GEH discusses its consideration of BL 80-01, “Operability of ADS Valve Pneumatic Supply.” The bulletin specified that nuclear power plant licensees must determine if hard-seat check valves were installed to isolate the ADS from the pneumatic supply system, determine if periodic leak tests were performed to assure availability emergency pneumatic supply, review seismic qualification of ADS pneumatic supply system, evaluate ADS operability, and take appropriate action. In Table 1C-2, GEH indicates that the design of the pneumatic supply to the ADS valves addresses the concerns with the potential loss of pneumatic pressure. In addition, the ESBWR has diverse means of depressurizing the RPV using the DPVs. The staff reviewed the GEH response to BL 80-01. In addition to the indicated GEH response, DCD Tier 2, Revision 9, Section 3.9.3.3.5, specifies the application of ASME Standard QME-1-2007, for valve designs not previously qualified, and requires the application of key aspects of the standard for valves previously qualified. Further, the inservice testing program will assess the operational readiness of the SRVs and DPVs on a periodic basis as discussed in Section 3.9.6 of this report. Because of the DCD provisions for valve design and qualification in accordance with ASME Standard QME-1-2007, and because COL Information Item 3.9.9-3-A requires COL applicants to provide a full description of the IST Program, the staff considers this BL resolved for the ESBWR design.

BL 80-25, “Operating Problems with Target Rock Safety-Relief Valves at BWRs,” December 19, 1980

In DCD Tier 2, Revision 9, Table 1C-2, GEH discussed the evaluation of BL 80-25 for the ESBWR design. In particular, GE stated that this BL did not apply to the ESBWR design because a different valve type was used and referenced Section 5.4.13 of the DCD. The staff discusses the SRVs in Section 3.9.6 of this report.

BL85-03, “Motor Operated Valve Common Mode Failures During Plant Transient Due to Improper Switch Settings,” November 15, 1985

In a previous revision to DCD Tier 2, Table 1C-1, GEH indicated that BL 85-03, and its Supplement 1 were not applicable to the ESBWR in that they involved an administrative, maintenance, or procurement communication. In its response to RAI 20.0-10, the applicant stated that it would revise Tables 1C-1 and 1C-2 to clarify the applicability of GLs and BL to COL applications, including BL 85-03 and its Supplement 1. DCD Tier 2, Revision 6, Tables 1C-1 and 1C-2 incorporated these changes in an acceptable manner, including indication that BL 85-03 and its Supplement 1 are applicable to the COL application. The Motor-Operated Valve (MOV) Testing program is addressed in Section 3.9.6 of this SER. Therefore, RAI 20.0-10 is resolved. Because of the DCD provisions for valve design and qualification in accordance with ASME Standard QME-1-2007, and because COL Information Item 3.9.9-3-A requires COL applicants to provide a full description of the IST Program (including the MOV Testing Program), the staff considers this BL resolved for the ESBWR design.

BL 86-01, “Minimum Flow Logic Problems that Could Disable RHR Pumps,” May 23, 1986

DCD Tier 2, Revision 9, Table 1C-2 addresses this issue.

In this BL the staff addressed concerns regarding RHR pumps, which also function as low pressure injection pumps during a LOCA, running dead-headed due to a postulated single failure of a flow sensing instrument. The RHR pumps do not function as ECCS pumps; this item is not applicable.

BL 93-03, "Resolution of Issues Related to Reactor Vessel Water Level Instrumentation in Boiling Water Reactors," May 28, 1993

This subject is also addressed by resolution of GL 92-04 in Section 20.5.1 of this report. Based on its review discussed in Sections 20.5.1 of this report, the staff finds that this BL is resolved for the ESBWR design.

20.6 Conclusion

On the basis of its review of the BLs and GLs issued between January 1, 1980 and February 24, 2005, and the review of the DCD Tier 2, Revision 9, the staff concludes that GEH adequately addressed operating experience in the ESBWR design as required by 10 CFR 52.47(a)(22). The applicant also addressed all the relevant TMI action plans items found in 10 CFR 50.34, and proposed technical resolutions of the USIs and medium- and high-priority GSIs as defined in NUREG-0933. The staff concludes that the applicant has adequately demonstrated that the ESBWR design complies with the requirements of 10 CFR 52.47(a)(8) and 10 CFR 52.47(a)(21).

21.0 TESTING AND COMPUTER CODE EVALUATION

21.1 Introduction

The GE–Hitachi Nuclear Energy (GEH) economic simplified boiling-water reactor (ESBWR) design is the first natural-circulation-cooled boiling-water reactor (BWR) reviewed by the U.S. Nuclear Regulatory Commission (NRC). The design incorporates many unique features, including a very large chimney arrangement above the core and a passive gravity-driven emergency core cooling system (ECCS). The features of the design necessitated an extensive review of the testing program and accident and transient analysis computer codes to establish their applicability to the ESBWR. However, since core uncover is not expected for any postulated break in the piping attached to the reactor pressure vessel (RPV), it was not necessary for the staff to review models and correlations for estimating fuel heatup.

The test and analysis program description in NEDC-33079P, “ESBWR Test and Analysis Program Description,” Class III, Revision 1, issued November 2005, provides an integrated plan to address the experimental and analytical work needed to analyze ESBWR performance for normal operations, transients, design-basis accidents (DBAs), stability, and anticipated transient without scram (ATWS) conditions in support of ESBWR design certification. A major product of all these activities is the assessed TRACG code for ESBWR analysis. The preapplication review of the ESBWR focused on the review of the TRACG code for loss-of-coolant accident (LOCA) and containment analysis; the staff safety evaluation documents the results of this review in a letter from W.D. Beckner (NRC) to L.M. Quintana (General Electric Nuclear Energy [GENE]), “Re-Issuance of Safety Evaluation Report Regarding the Application of General Electric Nuclear Energy’s TRACG Code to ESBWR Loss-of-Coolant (LOCA) Analyses,” dated October 28, 2004. The preapplication review did not include an evaluation of the test data and TRACG qualification for operational transients, ATWS, and stability. This chapter of the safety evaluation report (SER) discusses the applicability of the GEH testing program and scaling analysis to the updated ESBWR design submitted in the design control document (DCD) regarding LOCA performance, in addition to summarizing the key findings of the preapplication review.

As required by Title 10 of the *Code of Federal Regulations* 10 CFR Section 52.47(b)(2)(c)(2), GEH used experimental data from a number of basic and separate effects tests with generic applications to operating BWRs and the ESBWR, full-size component tests and integral systems tests performed specifically for the simplified boiling-water reactor (SBWR) and ESBWR, and BWR plant operation to qualify the TRACG code for the ESBWR LOCA analyses. Section 21.5.3 of this report summarizes the test data (excluding the basic tests) used to qualify the TRACG code initially for the SBWR and now for the ESBWR LOCA applications. The facilities described were designed and scaled based on the SBWR design. The staff reviewed the facilities for their applicability to the ESBWR design. The staff conclusions regarding applicability are based on a review of the test objectives, test descriptions, phenomena represented, and adequacy of the GEH scaling analysis, as discussed in Section 21.5.3 of this report. This assessment references the SBWR as well as the ESBWR design since the facilities were originally designed for the SBWR.

21.2 Limitations and Restrictions

Many of the safety systems of the ESBWR design represent new concepts in plant safety system design. As a result, an extensive scaled facility testing program was developed for the

predecessor concept, the SBWR design. While the SBWR was considerably smaller than the ESBWR, the two incorporate many system similarities. As noted in the introduction to this chapter, the ESBWR design does not experience core uncover for any postulated LOCA. The staff has reviewed the accident analysis computer codes on this basis. If any changes result in core uncover for any postulated LOCA, the conclusions regarding the acceptability of the computer codes will be invalid.

GEH scaled and designed the systems test facilities in such a way that few data were obtained regarding multidimensional phenomena. In addition, the GEH scaling analysis was based on the lumped-parameter technique. As such, the tests did not provide sufficient data to qualify the TRACG code for multidimensional spatial variations. Without multidimensional capability, the TRACG code is unable to accurately predict drywell mixing, noncondensable gas stratification, or buoyancy/natural circulation inside the containment. As a consequence of this limitation, the TRACG code will employ conservatively bounding ESBWR containment models. (For further discussion, see the staff evaluation presented in Section 21.5.3 of this report.)

21.3 Overview of GEH Testing Programs

In DCD Tier 2, Revision 9, Section 1.5.3, GEH described the ESBWR test program. NEDC-33079P provides the ESBWR test and analysis program description, which includes a detailed justification for the adequacy of the test database for application to the safety analysis. The phenomena identification and ranking table (PIRT) discussed in Section 2 of NEDC-33079P identifies specific governing phenomena, of which a significant fraction was concluded to be “important” in predicting ESBWR transient and LOCA performance. Most of these phenomena are common to those for operating BWRs. TRACG has been extensively qualified against separate effects tests, component performance tests, integral systems tests, and plant operating data listed in NEDC-33079P. The TRACG qualification report NEDE-32177P, “TRACG Qualifications,” Class III, Revision 2, documents this “base” qualification. This section describes specific tests related to the SBWR/ESBWR and test facilities beyond those used to create the previous qualification database.

GEH stated that, while all SBWR/ESBWR features are extrapolations from current and previous designs, two features (specifically, the passive containment cooling system [PCCS] and the gravity-driven cooling system [GDCCS]) represent the two most challenging extrapolations. Therefore, it was decided that, for these two cases, it was necessary to obtain additional test data that could be used to demonstrate the capabilities of TRACG to successfully predict SBWR/ESBWR performance over a range of conditions and scales. “Blind” pretest analyses of selected test conditions using only the internal correlations of TRACG were performed before the start of testing. “Blind” indicates that the analyst had no information on the results of the experiments. No “tuning” of the TRACG inputs was performed, and no modifications to the coding were anticipated as a result of these tests. A number of “double blind” pretest analyses were also performed for certification data experiments. “Double blind” indicates that the analyst had no information on either the results or the exact initial conditions of the experiments. These predictions were based on the as-designed facility configurations.

For the PCCS, the steady-state heat exchanger performance was predicted in full-vertical-scale 3-tube (GIRAFFE), 20-tube (PANDA), and prototypical 496-tube (PANTHERS) configurations, over the range of steam and noncondensable conditions expected for the SBWR. This process addressed scale and geometry differences between the basic phenomena tests performed in single tubes and larger scales, including prototype conditions. Transient performance was similarly investigated at two different scales in both gravity-driven integral full-height test for

passive heat removal (GIRAFFE) and Passive Nachwarmeabfuhr-und DrueckAbbau Testanlage (passive decay heat removal and depressurization test facility) (PANDA).

TRACG GDCS performance predictions were performed against the gravity-driven integrated systems test (GIST) and GIRAFFE/SIT test series. Pretest predictions have also been performed for the performance analysis and testing of heat removal system (PANTHERS) and PANDA steady-state tests.

GEH further stated that, in some cases, the ESBWR DCD did not delineate the detailed design of specific ESBWR plant equipment; in some instances, only the design requirements of the equipment were given. When this is the case, a requirement for testing of specific hardware is not required before design certification. However, plant-specific hardware will be tested before or during startup testing of the plant as part of the completion of the inspection, test, analysis, and acceptance criteria (ITAAC) provided in DCD Tier 1, Revision 9 and the initial test program described in DCD Tier 2, Revision 9, Section 14.2. For example, the plant startup test program will include the overall testing of the heat rejection capability of the isolation condenser system (ICS). Plant-specific startup tests will be conducted to confirm that each ICS meets the performance requirements prior to commercial operation as specified in DCD Tier 2, Revision 9, Section 14.2.8.2.34. Full-scale tests of an ICS module in the PANTHERS test facility, as well as experience with condensing heat exchangers in many industries, offer a high degree of confidence that the requirements will be met.

21.3.1 Major ESBWR Unique Test Programs

As indicated in the DCD, the vast majority of data supporting the ESBWR design were generated using the design of the previous BWR product lines. ESBWR-unique certification and confirmatory tests applicable to its design, as described in the DCD, are presented below.

The staff evaluation of ESBWR test programs in Section 21.5.3 of this report fully discusses testing issues unique to the ESBWR.

21.3.1.1 *Massachusetts Institute of Technology/University of California at Berkeley Single Tube Condensation Test Program*

Early in the SBWR program, researchers identified that information was needed to determine a heat transfer correlation for steam condensation in tubes in the presence of noncondensable gases. A test program was conducted to secure this information. This test program is documented in NEDC-32301P, "MIT and UCB Separate Effects Tests for PCCS Tube Geometry, Single Tube Condensation Test Program," issued March 1994.

The Single Tube Condensation Test Program was conducted to investigate steam condensation inside tubes in the presence of noncondensables. The work was independently conducted at the University of California at Berkeley (UCB) and the Massachusetts Institute of Technology (MIT). The work was initiated to obtain a database and a correlation for heat transfer in conditions similar to those that would occur in the SBWR/ESBWR PCCS tubes during a DBA LOCA. UCB researchers utilized three separate experimental configurations, and MIT researchers used one configuration. The researchers ran tests with pure steam, steam/air, and steam/helium mixtures with representative and bounding flow rates and noncondensable mass fractions. The results demonstrated that the system behaved as expected for the tests with conditions similar to the ESBWR design. The results of the tests at UCB became the basis for the condensation heat transfer correlation used in the TRACG computer code.

21.3.1.2 GIST Test Program

GIST is an experimental program conducted by GEH to demonstrate the GDCS concept and to collect data to qualify the TRACG computer code for ESBWR applications. DBA LOCAs representing a main steamline break (MSLB), bottom drainline break (BDLB), GDCS line break, and a no-break scenario (e.g., a loss of feedwater) were simulated.

Test data, documented in GEFR-00850, "Simplified BWR Program Gravity-Driven Cooling System (GDCS) Integrated Systems Test," issued October 1989, have been used in the qualification of TRACG to the ESBWR. Tests were completed in 1988 and documented by GEH in 1989. GIST data are used to validate certain features of the TRACG code.

21.3.1.3 GIRAFFE Test Program

The GIRAFFE Test Program, documented in NEDC-32606P, "SBWR Testing Summary Report," Class III, issued November 1996, is an experimental program conducted by the Toshiba Corporation to investigate the thermal-hydraulic aspects of the PCCS. Fundamental steady-state tests on condensation phenomena in the PCCS tubes were conducted. Simulations were run of DBA LOCAs and, specifically, the MSLB. GIRAFFE data have been used to substantiate PANDA and PANTHERS data at a different scale and to support validation of certain features of TRACG. Also, two additional series of tests have been conducted in the GIRAFFE facility. The first (GIRAFFE/helium) test demonstrated the operation of the PCCS in the presence of lighter-than-steam noncondensable gas; the second (GIRAFFE/SIT) test provided additional information regarding potential system interaction effects in the late blowdown/early GDCS period.

21.3.1.4 PANDA Test Program

The PANDA Test Program, documented in NEDC-32606P, is an experimental program run by the Paul Scherrer Institute (PSI) in Switzerland. PANDA is a full-vertical-scale, 1/25-volume-scale model of the SBWR system designed to model the thermal-hydraulic performance and post-LOCA decay heat removal by the PCCS. Both steady-state and transient performance simulations have been conducted. Testing at the same thermal-hydraulic conditions as previously tested in GIRAFFE and PANTHERS allows scale-specific effects to be quantified. Blind pretest analyses using TRACG were submitted to the NRC before the start of testing. PANDA data are used to validate certain features of the TRACG code.

21.3.1.5 PANTHERS Test Program

The PANTHERS Test Program, documented in NEDC-32606P, is an experimental program performed by Ente Nazionale per l'Energia Elettrica at Società Informazioni Esperienze Termoidrauliche (SIET) in Italy, with the dual purpose of providing data for TRACG qualification and demonstration testing of the prototype PCCS and ICS heat exchangers. Steam and noncondensables were supplied to prototype heat exchangers over the complete range of SBWR conditions to demonstrate the capability of the equipment to handle post-LOCA heat removal. Testing was performed at the same thermal-hydraulic conditions as those used in the GIRAFFE and PANDA testing. Blind pretest analyses of selected test conditions using TRACG were submitted to the NRC before the start of testing. PANTHERS data are used to validate certain features of the TRACG code.

In addition to thermal-hydraulic testing, an objective of PANTHERS was to demonstrate the structural adequacy of the heat exchangers to exceed the SBWR/ESBWR expected lifetime requirement. GEH stated that this was accomplished by pre- and post-test nondestructive examination, following cycling of the equipment in excess of requirements.

21.3.1.6 Additional PANDA Tests

A supplementary test program, documented in NEDC-33081P, "ESBWR Test Report," Class III, Revision 1, was also performed in the PANDA test facility to evaluate an earlier ESBWR configuration with the GDCS pool connected to the wetwell gas space rather than the drywell. These tests confirmed the expected increased margin to the containment design pressure for this ESBWR configuration. This series of tests also included injection of helium, providing data on PCCS performance with light noncondensable gases at an additional scale.

21.3.2 Scaling of Tests

GEH discussed the effects of scaling on the major SBWR and ESBWR tests in NEDC-32288P, "Scaling of the SBWR Related Tests," Class III, Revision 1; NEDC-33082P, Revision 1, "ESBWR Scaling Report," Class III; and the response to request for additional information (RAI) 6.3-1. These reports assess the features and behavior of the SBWR and ESBWR during challenging events. The analysis included the general (top-down approach) scaling considerations, the scaling of specific (bottom-up approach) phenomena, and the scaling approach for the ESBWR-specific tests.

The staff evaluation of GEH scaling methodology and RAI 6.3-1 resolution in Section 21.5.3 of this report provides a full discussion of scaling issues.

21.4 Overview of NRC Activities on the Test Programs

Thermal-hydraulic test programs unique to the ESBWR design were used to support qualification of analytical codes used in the design and licensing of the ESBWR nuclear power plant. These tests were performed as a part of the earlier SBWR plant design. The NRC performed quality inspections of these test programs as a part of the oversight activities needed to prepare the SBWR design for a licensing submittal.

These activities included observing selected tests at some of the SBWR test facilities and auditing the applicant's performance of a broad range of issues related to the following:

- Test facility design, instrumentation, and scaling
- Test data and analyses
- Quality assurance (QA)

During the inspections, procedural defects were noted and corrected, and in the end, the programs were determined to meet appropriate quality requirements. On the basis of its observations of these tests, as documented in test observation reports, the staff concluded that the applicant performed the design certification test programs in a competent, professional manner and gave due consideration to meeting the test specifications and acceptance criteria. The staff believed that the test programs provided useful data for evaluating the ESBWR passive safety system performance; however, the staff did perform a detailed review of the test results to reach a final judgment on the adequacy of the vendor's test programs. As discussed in Section 21.5 of this report, the staff, based on its evaluation, concluded that the SBWR

testing is also applicable to ESBWR design certification. Section 21.6.2.6 of this report provides a comprehensive summary of the QA inspections. The following sections summarize the quality inspection activities for the test programs.

21.4.1 GIRAFFE Test Programs

The Toshiba Corporation performed three separate sets of tests at its Nuclear Engineering Laboratory (NEL) in Kawasaki City, Japan, in support of the SBWR. The GIRAFFE test facility included all the major components of the SBWR design and had the capability to perform steady-state, component performance, and transient system response testing.

The first series of GIRAFFE tests (hereafter designated GIRAFFE Phase 1) were performed as development tests to confirm the operational feasibility of the SBWR concept and did not include the level of QA expected of a design-basis test. For this reason, only limited segments of the database were used in support of the SBWR and only for comparison to the steady-state passive containment cooling (PCC) performance tests of PANDA and PANTHERS.

The GIRAFFE/helium and GIRAFFE/SIT series were transient system performance tests run to design-basis QA standards. These tests investigated the effects of lighter-than-steam noncondensable gases on PCCS performance and potential systems behavior (e.g., isolation condenser [IC] operation during a LOCA), respectively.

The staff traveled to the Toshiba NEL in Kawasaki City (about 15 miles south of Tokyo, Japan) for further discussions about the GIRAFFE/SIT and "H"-series tests and to observe the performance of Test GS-2 as documented in "GIRAFFE/SIT Trip Report dated October 27, 1995," dated November 7, 1995. The test was nominally a repeat of GS-1 (i.e., a double-ended guillotine break of a GDCCS injection line), but with actuation of the PCCS and ICS. However, the discussions also included coverage of the preliminary results of a "shakedown" run of GS-2, which had been performed earlier.

The pretest procedures in GIRAFFE are relatively complex because of the necessity of initializing a test "on the fly." These complexities are increased when the ICS is used. GS-2 was the first test ever performed in GIRAFFE in which the ICS was brought on line at the test initiation pressure of about 1 megapascal (MPa) (145 psi [pounds per square inch]). Toshiba determined that it would be difficult to allow the ICS to operate during test initiation, with the condensate returning directly to the RPV, while maintaining pressure in the RPV. Thus, the ICS return to the RPV was valved off, and condensate was allowed to collect in the heat exchanger. If the accumulated condensate was allowed to flow to the RPV when the ICS was brought on line, it would distort the previously established RPV water level at the start of the test. Thus, the IC was drained outside the facility immediately before test initiation to allow proper loop conditions to be established. This procedure had not been tested before performance of GS-2. Therefore, Toshiba performed a shakedown run of that test to determine whether the ICS startup procedures accomplished the desired result. In addition, data were collected as though the shakedown run was an actual matrix test.

Post-test evaluation of the data demonstrated, to Toshiba's satisfaction, that the ICS startup procedure was successful, and the data were presented at the NEL as a "preview" of what would likely be seen when the test was performed "officially" later that day. The results of both tests are discussed further below.

The final activities at the NEL were to review the shakedown run of GS-2 and the observations of the official test run. Toshiba had plotted some of the key data from the shakedown run for comparison to both GS-1 and TRACG pretest analyses. To some extent, the responses of GS-1 and GS-2 were similar, especially near the start of the test. The minimum water level in the RPV was not as low as in GS-1. This was partly the result of a higher starting level, the value for which was determined from an analysis of the event. The ICS return valve opens before actuation of the automatic depressurization system (ADS) so that any accumulated water in the IC tubes and outlet plenum enters the RPV. This adds inventory and also helps depressurize the RPV. As a result, the predicted water level in the RPV when the pressure reaches about 1 MPa (145 psi), which is used to determine that parameter in GIRAFFE, is somewhat higher than if the ICS is not employed.

Other trends in the two tests were quite similar. The drywell and wetwell pressure curves in GS-1 and GS-2 were of the same general shape, with condensation in the drywell occurring because of the injection of GDACS water through the broken line. As a result, the wetwell pressure stayed higher than the drywell pressure, again causing numerous actuations of the vacuum breaker (VB); however, since the PCCS operates only when the drywell pressure is greater than the wetwell pressure, that system did not play a substantial role until very late in the transient. The peak containment pressure in GS-2 was about 10-percent lower than in GS-1, partly as a result of IC heat removal. The drywell and wetwell pressures began to increase shortly after the cessation of GDACS flow to the drywell (at 1 hour). In GS-1, after GDACS injection to the RPV had ended, steam production resumed in the RPV, and the venting of that steam through the ADS to the drywell brought the drywell pressure above that of the wetwell. Since the PCCS was shut off in GS-1, there was no energy removal to reduce the drywell pressure, and, near the end of the test, the drywell pressure exceeded the wetwell pressure sufficiently to open the LOCA vents. In GS-2, the ICS and PCCS were both available to remove energy once steam production resumed, and the PCCS operation prevented the drywell from reaching a pressure sufficiently greater than that of the wetwell to open the LOCA vents. In this test, therefore, the PCCS performed its function in limiting both overall drywell pressure (up to 2 hours post-LOCA) and the pressure difference between the drywell and the wetwell. No detrimental systems interactions were apparent, and safety-related injection and heat removal systems operated as designed.

Observation of the official run of the GS-2 test began shortly before test initiation. All loop manipulations required to “fine tune” the facility before test initiation can be done from the control room by using remote manual actuation of facility components. A small control room staff was required to accomplish those tasks. The staff followed the written procedures closely, and steps were noted on a test log/checklist, which was signed by the test engineer. Toshiba staff operated professionally, and appropriate consideration of testing QA appeared throughout the observed portion of the test initialization process and during the performance of the experiment. The staff was able to track key parameters, such as wetwell and drywell pressures, GDACS flow, selected temperatures, and water levels through control room digital displays or analog chart recorders. The GDACS initiation time, GDACS flow rate, RPV water level, and approximate pressure-time response of the wetwell and drywell agreed very closely with the results from the previous day’s shakedown run. Therefore, the two tests provided an indication of data repeatability, which was also valuable to the staff’s assessment of the test program.

The GIRAFFE “H”-series and GIRAFFE/SIT tests constitute well-run test programs conducted with appropriate attention to QA concerns. Section 21.5.3 of this report more fully discusses the staff’s concerns associated with some issues, such as scaling and test control (e.g., microheater

power). However, the data provided by these test programs were useful for code validation as part of the SBWR/ESBWR design certification effort.

21.4.2 PANTHERS Test Programs

As part of the SBWR design process, SIET and the European Nuclear Energy Association (ENEA) tested full-size prototype heat exchangers for the PCCS and ICS at the PANTHERS test facility in Piacenza, Italy. Ansaldo Spa designed and built the prototype PCCS and IC heat exchangers.

A readiness assessment was conducted for the PANTHERS/PCCS test program at SIET, and the staff reviewed the initial readiness assessment report. The purpose of the assessment was to ensure the technical adequacy of the facility and personnel to conduct the planned tests in accordance with test requirements. A specific goal was to ensure that all preparations were either complete or proceeding so that the test could be initiated with a high degree of confidence that quality results would be obtained. The assessment team concluded that personnel assigned to perform the tests were technically capable of conducting the test according to the requirements. Procedures and associated QA practices were in place and adequate to control the work.

The staff visited the SIET facility in Piacenza, Italy, to observe testing in the PANTHERS-PCCS facility for the GEH SBWR design as documented in "Summary of the visit on October 16, 1994, at the Società Informazioni Esperienze Termoidrauliche (SIET) Performance Analysis and Testing of Heat Removal System (PANTHERS) Test Facility for the SBWR Design," dated December 21, 1994. Major observations from the visit are discussed below.

Testing in PANTHERS provided considerable data on PCCS heat exchanger performance. Both GEH and ENEA (which was a partner in ownership of SIET Laboratories) supervised the testing, which was performed by a SIET team different from the one operating the SPES-2 facility. It was difficult to generalize on the basis of a single test, but the test operations crew demonstrated the same sort of competence and professionalism in PANTHERS testing as was noted previously for the operation of the SPES-2 facility.

The specific test observed by the staff involved measurement of the heat transfer capability of the PCCS unit with a steam-air mixture. In addition to degradation of heat transfer by the noncondensable gas, the water level in the PCCS surrounding the heat exchanger was lowered very gradually to determine the effect of that parameter on heat transfer performance. Observers noted very little effect of the lowered water level until a significant fraction (more than 50 percent) of the tube surface was uncovered. The staff believed that the observation of these activities was valuable in preparing for future observation of ICS testing. The staff had some concerns regarding the ICS structural integrity and design, particularly the leakage in the ICS during testing at the PANTHER-IC facility. The staff considered this an ICS structural integrity issue that needed to be resolved for the ESBWR design certification.

Section 21.5.3 of this report discusses the staff's concerns associated with some issues, such as the ICS structural integrity issue, and GEH's plan to resolve them.

21.4.3 PANDA Test Programs

GEH and PSI performed PANDA testing as a joint effort in Wuerenlingen, Switzerland. The PANDA facility included all of the major components of the SBWR design and had the capability to perform both steady-state component performance and transient system response testing.

The PANDA S-series tests were steady-state performance tests of the PCC and IC heat exchangers to identify any scale effects on PCC heat exchanger performance. The PANDA M-series tests were integral systems transient performance tests to demonstrate startup and long-term operation of the PCCS and to investigate potential systems interaction effects.

Test readiness review of the PANDA facility and test program was performed. The staff attended the review as observers. The purpose of this assessment was to ensure the technical adequacy of the facility and personnel to conduct the PANDA tests in accordance with the test requirements. The assessment was divided into horizontal and vertical reviews. The horizontal review consisted of determining the overall readiness of the facility, its personnel, and documentation. The vertical review consisted of a more detailed examination of a part of the facility (e.g., a single instrument line or data calculation) to verify the technical adequacy and correctness of the work. This review was held early in the program development to ensure that adequate time was available to address any potential deficiencies. Section 21.5.3 of this report discusses the issues regarding the validity of the test data and the nonprototypical features of the model.

21.5 Evaluation of Vendor (GEH) Testing Programs

21.5.1 Regulatory Criteria

The following requirements appear in 10 CFR 50.43(e) as referenced by 10 CFR 52.47(b)(2)(c)(2):

- The performance of each safety feature of the design has been demonstrated through analysis, appropriate test programs, experience, or a combination thereof.
- Interdependent effects among the safety features of the design have been found acceptable by analysis, appropriate test programs, experience, or a combination thereof.
- Sufficient data exist on the safety features of the design to assess the analytical tools used for safety analysis over a sufficient range of operating conditions, transient conditions, and specified accident sequences, including equilibrium core conditions.

21.5.2 Summary of Technical Information in the Application

Section 21.3 of this report provides an overview of the vendor (GEH) testing program.

21.5.3 Staff Evaluation

21.5.3.1 Full-Size Component Tests

MIT/UCB Single Tube Condensation Test Program

The Single Tube Condensation Test Program was conducted to investigate steam condensation inside tubes in the presence of noncondensables. The work was independently conducted at UCB and MIT, as described in NEDC-32301. The work was initiated to obtain a database and correlation for heat transfer in conditions similar to those that would occur in the SBWR/ESBWR PCCS tubes during a DBA LOCA. Researchers utilized three separate experimental configurations at UCB, while researchers at MIT used one configuration. Tests were run with pure steam, steam-air, and steam-helium mixtures with representative and bounding flow rates and noncondensable mass fractions. The results demonstrated that the system behaved as expected for all tests, with either of the noncondensables, for forced flow conditions similar to the ESBWR design. The results of the tests at UCB are the basis for the condensation heat transfer correlation used in the TRACG computer code.

Condensation on the PCCS primary side is a function of the mass flow rate and noncondensable fraction. The TRACG correlation is based on UCB test data. The correlation is qualified with UCB and MIT single tube, approximately full-length tests. PANTHERS provided confirmatory qualification.

The staff concludes that the experimental programs conducted for TRACG qualification of PCCS tube-side heat transfer are adequate for the condensation-driven mode. GIRAFFE and PANDA tests have shown that long-term containment performance is not highly sensitive to this correlation because the venting of noncondensables allows the PCCS heat removal rate to match the reactor decay heat for the long term. The staff, therefore, finds that the test data are sufficient for developing the condensation heat transfer correlation used in the TRACG code and meet the requirements of 10 CFR 50.43(e).

PANTHERS/PCCS Tests

This program tested a full-size PCCS condenser for the SBWR. The test objectives were to (1) demonstrate that the prototype PCCS heat exchanger for the SBWR was capable of performing as designed with respect to heat rejection (component performance), (2) provide a sufficient database to confirm the adequacy of TRACG to predict the quasi-steady heat rejection performance of a prototype PCCS heat exchanger over a range of airflow rates (to simulate nitrogen in the SBWR containment), steamflow rates, operating pressures, and superheat conditions that span and bound the SBWR (and ESBWR) range, and (3) determine and quantify any differences in the effects of noncondensable gas buildup in the PCCS heat exchanger tubes between lighter-than-steam and heavier-than-steam gases (concept demonstration).

A full-size PCCS condenser of the SBWR consists of two identical modules, and each module consists of a top header, a number of vertical condenser tubes, and a bottom header. The PANTHERS/PCCS tests provided data for a full-size, two-module PCCS condenser submerged in a pool of water. Although the tests focused on the performance of a PCCS condenser for the SBWR, the data are applicable to a PCCS condenser in the ESBWR, which has the same condenser tube diameter, length, and pitch as the condenser tested in PANTHERS for the SBWR. The only difference is that the PCCS condenser in the ESBWR has about 35-percent more tubes than does the SBWR. As a result, an ESBWR PCCS condenser is expected to

have a heat removal rate about 35-percent higher than that measured in the PANTHERS/PCCS condenser.

GEH, Ansaldo Spa, ENEA, and SIET performed PANTHERS/PCCS testing as a joint effort in Piacenza, Italy. The test facility consisted of a prototype PCCS unit originally designed to represent the SBWR, a steam supply, an air supply, and vent and condensate volumes sufficient to establish PCCS thermal-hydraulic performance. The heat exchanger was a prototype unit, built by Ansaldo Spa using prototype procedures and prototype materials. The PCCS pool had the appropriate water volume for a prototypical PCCS unit.

For the steady-state performance tests, the facility was purged with steam and placed in a condition where steam or an air-steam mixture was sent to the PCCS and the flows of the condensate and vented gases were measured. Once steady-state conditions were established, data were collected for a period of approximately 15 minutes. Ninety-seven steady-state tests were performed, including the steam-only tests, with either saturated or superheated steam. Test conditions covered the entire range of the PCCS inlet flow rates and pressures expected in the SBWR.

Transient tests were conducted by first establishing steady-state conditions and then either varying the water level in the PCCS pool or allowing the unit to fill up from an injection of noncondensable gases with the ventline closed off by a blind flange.

Investigators evaluated several phenomena, including the overall PCCS heat removal rate, pool-water-level effect on PCCS performance, mass flow rate into the PCCS, condensation inside the tubes with or without the presence of noncondensable gases, poolside heat transfer, parallel PCCS tube effects, and parallel PCCS module effects.

Full-size component tests were conducted with the test parameters covering those expected in the SBWR and ESBWR (after a 35-percent increase in the PCCS heat removal rate as tested to account for the approximately 35-percent increase in the number of condenser tubes) during LOCAs.

Test results demonstrated that a prototype PCCS heat exchanger for the ESBWR is capable of performing as designed with respect to heat rejection and provided a sufficient database to confirm the adequacy of the TRACG code to predict the quasi-steady heat rejection performance of a prototype heat exchanger over a range of airflow rates (to simulate nitrogen in the containment), steamflow rates, operating pressures, and superheat conditions that cover the expected ranges of values of the parameters for the ESBWR.

Many of the tests were conducted at a pressure higher than the expected containment pressure in the ESBWR during a LOCA, such as MSLB, GDCSLB, or a BDLB. Also, lower pressure data bracket the expected range of the containment pressure in the ESBWR.

Researchers measured temperature at the inside and outside walls of four condenser tubes, but did not measure the bulk gas temperature inside these tubes. The heat transfer coefficient inside a tube cannot be derived from the test data. No measurements were taken of mass flow rate and noncondensable gas concentration at the inlet of a condenser tube where tube wall temperatures were measured. As a result, a correlation between the heat transfer coefficient and the fluid velocity could not be derived from the test data. The results of the Single Tube Condensation Test Program performed at UCB were the basis for the condensation heat

transfer correlation used in the TRACG code. Sections 21.3.1.1 and 21.5.3.1 of this report discuss the UCB test program.

Since the PCCS tested at the PANTHERS-PCCS facility is equivalent to a full-size PCCS condenser in the SBWR, no scaling analysis was necessary, and the test data provided a global heat removal rate for a full-size condenser in the SBWR. The PANTHERS/PCCS data confirmed that a PCCS condenser in the SBWR is capable of a heat removal rate of 10 megawatts (MW) (or higher depending on the inlet conditions) as designed. For the ESBWR, the heat removal rate of a PCCS condenser is expected to be around 11.0 MW (with 35-percent more condenser tubes than the one tested at the PANTHERS-PCCS facility).

The PANTHERS/PCCS tests were not designed to provide local thermal-hydraulic parameters, such as the heat transfer coefficient, mass flow rate, and noncondensable gas concentration, inside a condenser tube. As discussed above, the UCB test program provided the necessary data to qualify TRACG for these phenomena.

In conclusion, the staff believes that the PANTHERS/PCCS test data cover a broad range of the SBWR and ESBWR parameters, including inlet pressure, total mass flow rate, and total noncondensable gas concentration to confirm the PCCS heat removal rate under various LOCA conditions. Therefore, the PANTHERS/PCCS data are acceptable as a valid database to qualify the TRACG code for the global heat removal rate of a PCCS condenser under the expected LOCA conditions in the ESBWR.

PANTHERS/ICS Tests

An ICS unit consists of two identical modules, with each module comprising a top header, a number of vertical condenser tubes, and a bottom header. The PANTHERS/ICS tests provide data for one full-size module of the ICS condenser (consists of two modules) submerged in a pool of water. Note that an ICS in the ESBWR is identical to the ICS in the SBWR tested in the PANTHERS/ICS tests.

The test objectives were to (1) demonstrate that the prototype ICS heat exchanger is capable of performing as designed with respect to heat rejection, (2) provide a sufficient database to confirm the adequacy of TRACG to predict the quasi-steady heat rejection performance of a prototype ICS heat exchanger over a range of operating pressures that span and bound the ESBWR range, (3) demonstrate the startup of the ICS unit under anticipated transient conditions, and (4) demonstrate the capability of the ICS design to vent noncondensable gases and to resume condensation following venting.

PANTHERS/ICS testing was performed at SIET in Piacenza, Italy. The facility consisted of a prototype ICS module, a steam supply vessel simulating the SBWR reactor vessel, a vent volume, and associated piping and instrumentation sufficient to establish ICS thermal-hydraulic performance.

The ICS tested was one module of a full-scale, two-module vertical tube heat exchanger designed and built by Ansaldo Spa. Only one module was tested because of the high energy rejection rate of the ICS unit and inherent limitations of facility and steam supply size. The ICS was a prototype unit, built using prototypical procedures and prototypical materials. The SBWR has six modules (three heat exchanger units). The ICS was installed in a water pool having one-half the appropriate volume for one SBWR ICS assembly.

For the steady-state tests, the steam supply to the steam vessel was regulated such that the vessel pressure stabilized at the desired value. A constant water level was maintained in the pressure vessel by draining condensate back to the power plant. Data were acquired for a period of approximately 15 minutes. Then the steam supply was increased or decreased to gather data at a different operating pressure, or testing was terminated. In all cases, flow into the ICS was driven by natural circulation, as is the case for the SBWR/ESBWR.

As with the PCCS tests, transient tests were conducted by first establishing steady-state conditions and then either varying the water level in the ICS pool or allowing the unit to fill up from an injection of noncondensable gases. The gases were subsequently purged through ventlines located on both the lower and upper headers.

In terms of phenomena, investigators evaluated the ICS heat removal rate, effect of the pool's water level on the ICS performance, mass flow rate into the ICS, and poolside heat transfer.

Full-size component tests were conducted with the test parameters covering those expected in the ESBWR during both normal and accident conditions. Since the ICS tested has one of the two identical modules of a full-size ICS, a scaling analysis was not necessary, and the test data were directly applicable to an ICS in the ESBWR (which has twice the heat removal rate of the ICS tested at the PANTHERS-IC facility).

Researchers measured temperature at the inside and outside walls of eight condenser tubes, but did not measure the bulk gas temperature inside these tubes. As a result, the heat transfer coefficient inside the tubes could not be derived from the test data. No measurements were made of the mass flow rate and noncondensable gas concentration at the inlet of a condenser tube where tube wall temperatures were measured. As a result, a correlation between the heat transfer coefficient and the fluid velocity could not be derived from the test data. Because such a correlation was not a test objective, the staff finds this acceptable. As discussed above, the UCB test program provided the necessary data to qualify TRACG for these phenomena.

The staff had some concerns regarding the ICS structural integrity and design, particularly the leakage in the ICS that occurred during testing at the PANTHERS-IC facility. This was considered an ICS structural integrity issue that needed to be resolved for the ESBWR design certification. GEH stated that the O-ring design had been changed to a Helicoflex self-energizing O-ring design that is more resilient to distortion. GEH further stated that closing of the condensate return valve will be controlled to limit the temperature gradients associated with shutdown and cooldown of the ICS heat exchanger. However, Table 14.2-1 of DCD Tier 2, indicated that the ICS performance test will be conducted at a medium-power level, but not at a high-power level. Because one of the objectives of a power ascension test should be to demonstrate ICS structural integrity, the staff believes that an ICS performance test at high power would be of more value because the operating conditions at high power are expected to be more challenging to the structural integrity of the ICS. Therefore, the staff requested in RAI 14.2-3 that the ICS performance test be conducted at high power, rather than at a medium-power level.

In response, GEH stated that the ascension test matrix (Table 14.2-1 of DCD Tier 2) proposed that the ICS be tested at medium (up to about 75-percent rated) power. Pressure and temperature, not the reactor power level, affect the structural integrity of the ICS. When the reactor startup begins, the reactor is brought to the rated pressure and temperature at approximately 5-percent power, as stated in DCD Tier 2, Revision 9, Section 14.2.1.3. As the power level increases, the same rated pressure and temperature are maintained; therefore, it is

sufficient to conduct the ICS test at medium power. Hence, the staff finds that testing at high power would not be more challenging from the viewpoint of the structural integrity of the ICS, and no DCD change is required. Based on the applicant's response, RAI 14.2-3 is resolved.

The ICS tested at the PANTHERS-IC facility was one module of a full-scale, two-module ICS in the ESBWR. The staff concludes that the test results using one module demonstrated the capability of a prototype ICS module to perform as designed with respect to heat rejection and provided a database for TRACG qualification regarding the quasi-steady heat removal rate of an ICS. The PANTHERS/ICS data are, therefore, acceptable as a valid database to qualify the TRACG code for the ICS global heat removal rate.

Depressurization Valve Tests

Researchers conducted full-size depressurization valve (DPV) tests at the Wyle Laboratory in the United States. The test objective was to demonstrate reliable operation of the DPV.

Mass flow rate in a DPV was not measured because the tests focused on the successful opening of the DPV. GEH conducted full-size testing of the DPV to demonstrate its operation and reliability.

In RAI 3.9-1, the staff requested that GEH submit the test reports for the DPVs. Section 3.9 of this report presents the staff's evaluation of the DPV test results. Based on the applicant's response, RAI 3.9-1 is resolved.

Vacuum Breaker Tests

Researchers conducted full-size VB tests at a facility in Italy. The test objective was to demonstrate reliable operation of the VB. The opening and closing pressures of a VB were measured.

In RAI 3.9-1, the staff also requested that GEH submit the VB test reports. Section 3.9 of this report provides the staff's evaluation of the VB test results. Based on the applicant's response, RAI 3.9-1 is resolved.

21.5.3.2 Integral Systems Tests

Integral systems tests were conducted at the GIST, GIRAFFE, and PANDA test facilities.

GIST Tests

The test objectives were to demonstrate the technical feasibility of the GDSCS concept and to provide a sufficient database to confirm the adequacy of the TRACG code in predicting GDSCS flow initiation times, GDSCS flow rates, and RPV water levels.

GIST focused on the ability of the GDSCS to maintain core cooling in a LOCA. GEH performed the tests in San Jose, CA, in 1988. The GIST facility was a section-scaled simulation of the 1987 SBWR design configuration, with a 1:1 vertical scale and a 1:508 horizontal area scale of the RPV and containment volumes. Because of the 1:1 vertical scaling, the tests provided the real-time response of the 1987 SBWR pressures and temperatures.

The GIST program included the effects of various plant conditions on GDCS initiation and performance. The GIST facility consisted of four pressure vessels—the RPV, upper drywell, lower drywell, and wetwell. The wetwell included the GDCS fluid. The RPV included internal structures, an electrically heated core, and bypass and chimney regions.

The GIST facility modeled the SBWR plant behavior during the late stage of the RPV blowdown. The tests were started with the RPV at 791 kilopascals (kPa) (absolute) (115 pounds per square inch [psi]) and continued until the GDCS flow initiated and flooded the RPV. Four types of tests were conducted—MSLB, GDCSLB, BDLB, and a no-break scenario (e.g., loss of feedwater). Researchers conducted 29 integral systems tests. All these tests lasted from 600 to 1,210 seconds.

Investigators evaluated the integral systems response of the RPV and containment during the late blowdown phase and GDCS injection phase of LOCAs.

Unlike the PANDA M-series and GIRAFFE tests, the GIST tests were conducted in a facility that was based on an older SBWR design that did not include a separate GDCS pool. Instead, the elevated suppression pool (SP) also served as the GDCS coolant source. In this respect, the PANDA and GIRAFFE design was closer to that of the ESBWR.

Three kinds of LOCAs were tested in GIST: an MSLB, GDCSLB, and BDLB. Sensitivity studies performed by GEH at that time indicated that these breaks were expected to bracket other LOCAs in terms of break sizes, locations, and coolant flow. Nineteen LOCA tests were conducted, which included eight MSLB tests, four GDCSLB tests, and seven BDLB tests. For the same kind of LOCA (e.g., the MSLB), initial test conditions were varied among the reactor vessel water level, SP level, and the number of operational GDCS injection lines. The figure of merit, the critical safety parameter, for the GIST tests was the minimum downcomer water level.

The tests demonstrated the technical feasibility of depressurizing the RPV to sufficiently low pressures (i.e., below the static head of an elevated pool of water in the containment) to enable coolant injection to the core.

Design limitations caused two phenomenon distortions. First, GIST used two vertical pipes as the replacement for the annular downcomer of the reactor vessel between the lower plenum and the upper plenum above the core. Asymmetrical behavior observed during part of the tests revealed a two-phase or frothy mixture in one downcomer pipe and phase separation (low-void water in the bottom with steam above) in another downcomer pipe. This kind of asymmetry is not expected to occur in the annular vessel downcomer of the ESBWR, since it does not have the separation found in the test facility's separate downcomer pipes. Second, a single standpipe was installed above the upper plenum of the RPV, where periodic percolation was identified during part of the tests, which led to periodic variations in the RPV pressure. However, these distortions are nonprototypical and are not expected to invalidate the overall integral systems behavior observed in the GIST tests.

The staff concludes that the GIST tests demonstrated the technical feasibility of the GDCS concept, which involves RPV depressurization to allow coolant injection to the vessel from an elevated pool of water in the containment. Despite the phenomenological distortions described above, the GIST tests demonstrate that the overall GDCS performance in providing coolant to a depressurized RPV remains valid for a broad spectrum of LOCAs. The GIST data are therefore acceptable as a valid database to qualify the TRACG code for the late blowdown and early GDCS injection phases of a LOCA in the ESBWR.

GIRAFFE/Helium Tests

The test objectives were to (1) demonstrate the operation of a PCCS with the presence of a lighter-than-steam noncondensable gas, including the process of purging noncondensable gases from the PCCS, (2) provide a database to confirm the adequacy of TRACG to predict SBWR containment system performance in the presence of a lighter-than-steam noncondensable gas, including potential systems interaction effects, and (3) provide a tie-back test, which includes the appropriate QA documentation, to repeat a previous GIRAFFE test.

GIRAFFE/helium tests were performed as a joint effort by GEH and Toshiba in Kawasaki City, Japan. The GIRAFFE facility is a large-scale, integral system test facility designed to exhibit post-LOCA thermal-hydraulic behavior similar to the SBWR systems that are important to long-term containment cooling following a LOCA.

The global volume scaling of the facility is approximately 1:400, with a nominal height scaling of 1:1. The SBWR components simulated in the facility are the RPV, PCCS, GDCS, drywell, wetwell, and connecting piping and valves. Five separate vessels represent the SBWR RPV, drywell, wetwell, GDCS pools, and PCCS pool. The facility was equipped with one PCCS to represent the three SBWR PCCS condensers. Electric heaters provided a variable power source to simulate the core decay heat and the stored energy in the reactor structures.

For the helium series tests, once the initial test conditions were established, all control (except for the decay of RPV power and helium injection, if called for) was terminated, and the GIRAFFE containment was allowed to function without operator intervention (except for the VB, which was operated manually to simulate automatic operation in the SBWR, and the minor wetwell microheater power adjustments that were made to compensate for facility heat losses).

In the GIRAFFE/helium tests, the phenomenon investigated was the integral system response of the RPV and containment during the long-term cooling phase of LOCAs. Researchers conducted four tests to demonstrate the PCCS operation with the presence of a lighter-than-steam noncondensable gas (using helium as a substitute for hydrogen gas) and a heavier-than-steam noncondensable gas (nitrogen). Test H1 was the base case test, and the initial test conditions were based on TRACG calculations for the SBWR during the long-term cooling phase at 1 hour after the break initiation (RPV initial pressure at 295 kPa (absolute) [42.8 psi absolute]). Test H2 was a repeat of Test H1, but with helium replacing the nitrogen in the drywell. Test H3 was a variation of Test H1, but with helium replacing some steam in the drywell. Test H4 was similar to Test H1, but with a constant helium injection into the drywell. In addition, two other MSLB tests, Tests T1 and T2, were conducted with nitrogen as the only noncondensable gas in the containment.

Heat loss was a concern in the GIRAFFE facility, which was tall and thin. Electric microheaters were installed to wrap around the metal walls of the drywell, wetwell, and GDCS pool, which were covered with an insulation material. Microheater power for each component was determined during the shakedown tests to compensate for the heat loss. Since the microheater power could not fully compensate for the heat loss, the RPV electric heater power was raised above the scaled decay heat to further compensate for the heat loss in the facility with the microheaters on. However, this provision could not eliminate the local heat loss in the lower drywell, which was found to be significant. The heat loss has the potential to introduce some local distortions in the test data and therefore should be considered in the code uncertainty evaluation.

Only two noncondensable gas sampling locations were in the drywell, one at the top of the drywell and the other at the very bottom of the drywell located in the lower drywell where the local heat loss was significant. The heat loss at the bottom sampling location has the potential to somewhat distort the noncondensable gas behavior in the drywell. This problem was compounded by the scarcity of the noncondensable sampling locations. For the wetwell gas space, there was only one noncondensable gas sampling location. However, unlike the lower drywell, the wetwell wall heat loss was found to be insignificant. The scarcity of the noncondensable gas sampling locations and the heat loss problem at the lower drywell tended to reduce the quality of the containment noncondensable gas distribution data. These limitations of test data were overcome by employing conservatively bounding TRACG containment models.

All the GIRAFFE/helium tests (including Tests T1 and T2) focused on the long-term cooling phase of the MSLB and did not include the late blowdown and GDSCS phase. The GIRAFFE/helium tests demonstrated the ability of the PCCS to maintain containment cooling during the long-term cooling phase of the MSLB, which was the most critical LOCA to challenge the containment for the SBWR. Investigators evaluated the impact on the PCCS performance for both heavier-than-steam (nitrogen gas) and lighter-than-steam (helium gas) noncondensable gases present in the containment under various test conditions.

Because of the heat loss at the lower drywell, noncondensable gas distribution in the drywell is distorted by having a much higher noncondensable concentration (because of local steam condensation) than expected in the lower drywell. Furthermore, since there were only two noncondensable sampling locations in the drywell and only one in the wetwell gas space, extra efforts were needed to interpret and use the data to qualify the TRACG code with regard to the noncondensable gas distributions in the containment. Nevertheless, the many measurements of pressures, temperatures, and water levels were sufficient to explain the containment response in the presence of the heavier-than-steam and lighter-than-steam noncondensable gases.

The GIRAFFE/helium tests were based on the SBWR design, which is very similar to the ESBWR design in terms of the RPV and containment phenomena expected in a LOCA. Furthermore, the design changes from the SBWR to the ESBWR did not introduce any new phenomena. In view of the above, the staff concludes that the GIRAFFE/helium tests provided a valid database to qualify the TRACG code for the long-term cooling phase of a LOCA involving both lighter-than-steam and heavier-than-steam noncondensable gases, although a careful examination of all the data was necessary.

GIRAFFE Systems Interactions Tests

The test objective was to provide a database to confirm the adequacy of TRACG to predict the SBWR ECCS performance during the late blowdown phase and GDSCS injection phase of a LOCA, with specific focus on potential systems interaction effects.

Researchers conducted a series of four transient systems tests to provide an integral systems database for potential systems interaction effects in the late blowdown and GDSCS injection phases. All four tests involved liquid breaks—three GDSCSLBs and one BDLB. Tests were performed with and without the ICS and PCCS in operation and with two different single failures.

The tests investigated the post-LOCA thermal-hydraulic behavior (especially the RPV pressure transient and water-level transient), the GDSCS injection characteristics, and possible systems

interactions. The test facility modeled the whole containment system of the SBWR. The SBWR components modeled in the facility were the RPV, ICS, GDCS, PCCS, drywell, wetwell, and connecting piping and valves. Major portions of the SBWR containment (drywell, wetwell, and GDCS pool, as well as the ICS and PCCS pools) were modeled using separate vessels.

The PCCS unit was the same as that used for the GIRAFFE/helium tests and consisted of a steam box, heat transfer tubes, and a water box. The PCCS had three heat transfer tubes corresponding to the scaled volume. The heat transfer tubes were full height, and the internal tube flow area was almost the same as the scaled SBWR flow area. One scaled ICS was mounted above the drywell vessel. The ICS had three tubes, two of which were plugged to reduce the heat transfer surface of the unit. This single condenser represented the two ICS condensers found in the SBWR.

Testing followed a methodology very similar to that used in the PANDA and GIRAFFE/helium tests. Once the initial conditions for a given test were established, all controls (except for the decay of RPV power) were terminated. The GIRAFFE RPV and containment were allowed to function without operator intervention. The GDCS pool-to-drywell flow was manually terminated at 1 hour in the GDCS break cases to avoid an inappropriate emptying of the pool. This was necessary since a single pool in the GIRAFFE simulated the three SBWR pools, only one of which would have pool-to-drywell flow. Manually stopping GDCS flow to the drywell in the GIRAFFE tests simulated the end of draining for that one pool in the SBWR and maintained the simulation of flow from the remaining pools to the RPV.

Phenomena associated with the integral systems tests were investigated. Integral systems responses of the RPV and containment in the late blowdown and GDCS injection phases of the GDCSLB and BDLB were measured. By comparing two similar GDCSLB tests with and without PCCS and ICS operation, investigators could assess interactions between the PCCS/ICS and GDCS.

Four integral systems tests were conducted to assess the GDCS performance in maintaining a covered core with and without the operation of the ICS and PCCS. Two kinds of LOCAs were investigated with break locations below the main steamline elevation—GDCSLB and BDLB. Test GS1 comprised a GDCSLB without the operation of the PCCS and ICS, assuming a DPV failure (failed to open upon demand). Test GS2 was similar to Test GS1, but included the operation of the PCCS and ICS. Test GS3 was a BDLB with the operation of the PCCS and ICS, assuming a DPV failure. Test GS4 was a GDCSLB with the operation of the PCCS and ICS, assuming a valve failure on a GDCS injection line. These tests complemented the GIRAFFE/helium tests in which only the MSLB was investigated. Potential interactions between the GDCS operation and the PCCS/ICS operation were assessed.

The GIRAFFE heat loss problem, discussed in the GIRAFFE/helium tests, was also present in the GIRAFFE systems interactions tests. Although electric microheaters were used around the drywell, wetwell, and GDCS pool, and the RPV heater power was increased beyond the scaled decay heat to compensate for the heat loss, the heat loss problem could not be fully eliminated. For instance, the local heat loss in the lower drywell was found to be significant. As indicated earlier, heat loss has the potential to introduce some local distortions in the test data and, therefore, should be considered in code uncertainty evaluation.

GIRAFFE/systems interactions tests lasted only 2 hours, which was not long enough to lead to the potential opening of the equalizing lines to provide SP water to the RPV. As a result, the equalizing line mass flow was not observed in the test data.

In all four tests conducted, the GDCS injection ran smoothly without noticeable flow oscillations. It performed well in keeping the core covered and maintaining core cooling. Comparing tests GS1 and GS2, the PCCS/ICS operation had no adverse impact on GDCS performance and led to a lower containment pressure as expected. Operation of the ICS significantly reduced the steamflow available to the PCCS, except for the initial 200 to 300 seconds.

In RAI 21.5-1, the staff asked GEH to clarify in the DCD the importance of the SP equalization line for long-term cooling, particularly the long-term PIRT ranking of the equalization line and, if necessary, to describe appropriate testing.

In response, GEH stated that the equalization line valves are not expected to open for a LOCA resulting from a break in any of the lines in the current ESBWR design, as submitted in the DCD. The results for the downcomer level response for the first 12 hours following a BDLB, feedwater line break (FWLB), GDCS line break, and MSLB showed that the downcomer water level stabilized at an elevation well above the elevation of the L0.5 trip (1 meter [m] [3.28 feet [ft]] above the top of active fuel and approximately 8.5 m [26.2 ft] above the bottom of the RPV). The lowest level in the long term occurs for the GDCS line break, which still has more than a 1-m (3.28-ft) margin to L0.5. This resulted from two changes in the current design relative to the previous design analyzed: (1) a larger GDCS pool volume and (2) a smaller volume in the lower drywell.

GEH further stated that Table 2 in “GE Response to Results of NRC Acceptance Review for ESBWR Design Certification Application—Item 2,” dated October 20, 2005, showed an incorrect “High” ranking for equalization line friction (EQ1). This table was extracted from a previous report, which did not reflect the changes in the ESBWR design mentioned above. Therefore, the ranking for SP equalization line (EQ1) in the PIRT should be “N/A” (not applicable), because the equalization line valves are not expected to be activated for any design-basis events in the current ESBWR design. The staff finds that the GEH response resolves RAI 21.5-1, and therefore, no additional testing is required.

The GIRAFFE/helium tests were based on the SBWR design, which is very similar to the ESBWR design in terms of the RPV and containment phenomena expected in a LOCA. Furthermore, no new phenomena were introduced as a result of the design changes from the SBWR to the ESBWR. Accordingly, the staff concludes that the GIRAFFE systems interactions tests provide a valid database to qualify the TRACG code for the late blowdown and GDCS injection phases of a LOCA.

PANDA M-Series Tests

The test objectives were to (1) provide a sufficient database to confirm the capability of TRACG to predict SBWR containment system performance, including potential systems interaction effects, and (2) demonstrate startup and long-term operation of a PCCS.

PANDA M-series tests were performed as a joint effort by GEH and PSI in Wuerenlingen, Switzerland. The test facility was a large-scale integrated containment structure, which was a 1/25-volumetric, full-height, scaled model of the SBWR containment. It was a modular facility with separate pressure vessels representing the RPV, drywell, wetwell, and GDCS pool. The facility was equipped with three scaled PCCS heat exchangers and one ICS unit (scaled from two SBWR ICS units), each with a separate pool of water. Electrical heaters were used in the RPV to simulate decay heat and the thermal capacitance of the RPV walls and internals in the SBWR. The test facility also had interconnecting piping arrangements needed to conduct the

MSLB tests. PANDA had all the necessary components to conduct the integral systems tests to investigate the long-term cooling phase of a DBA, namely the MSLB accident which was expected to be the most challenging LOCA to the containment for the SBWR.

The tests were started at an equivalent condition from about 1,040 seconds (transition from the GDCS injection phase to the long-term cooling phase) to about 3,600 seconds (beginning of the long-term cooling phase) after the initiation of the MSLB in the SBWR. The duration of a test was up to 20 hours.

When the initial conditions for a given test were established, all controls were terminated except for automatic control of the wetwell-to-drywell VB position and the electric heater simulation of the RPV structure stored energy release and core decay heat power. The PANDA containment was then allowed to function without operator intervention. The only exceptions to the procedure described above were for Tests M3A and M3B, which included operator action to maintain PCCS pool level, and Test M6/8 during which the operator established a drywell-to-wetwell flowpath (bypass leakage) and later valved the ICS unit out of service.

The integral systems response of the RPV, drywell, and wetwell was investigated for the late GDCS injection phase and long-term cooling phase of an MSLB LOCA. PCCS performance for maintaining containment cooling was assessed.

The PANDA M-series tests consisted of 10 integral systems tests for the MSLB that covered a broad spectrum of test conditions expected in the SBWR. Except for Test M9, these tests focused on the long-term cooling phase of the MSLB (occurring at about 1 hour after break initiation). Test M9 included both the late GDCS injection phase (with the initial test conditions based on 1,040 seconds after the break initiation in the SBWR) and the long-term cooling phase of a LOCA. These tests demonstrated successful operation of the PCCS for maintaining adequate containment cooling under various MSLB conditions in a large test facility.

PANDA M-series tests were designed to focus on the MSLB accident because that was expected to be the most challenging LOCA to the containment for the SBWR. There was no lower drywell in the PANDA test facility, and consequently, the GDCSLB and BDLB could not be tested. Potential opening of the GDCS equalizing lines to provide SP water to the RPV could not be investigated. (See the previous discussion of RAI 21.5-1.)

The volume of the GDCS pool was much smaller than the scaled volume, and consequently, the amount of water was insufficient to cover the entire spectrum of the GDCS injection phase. As a result, the PANDA tests investigated the long-term cooling phase and only a portion of the GDCS injection phase of the MSLB LOCA. Because the primary objectives of the test were to investigate long-term containment phenomena and not the GDCS injection phase, the staff finds this acceptable.

Large oscillations occurred in the main steamline mass flow rates when the water level in the RPV was high (close to the top of the chimney). The flow oscillations were greatly reduced if the initial RPV water level was at a low level (several meters below the top of the chimney). The staff believes that the flow oscillations might have been caused by design distortions in the PANDA test facility (e.g., lack of core inlet orifices, fuel assemblies, steam separators, dryers, and multiple fuel assemblies in the RPV) although they did not prevent the PCCS from maintaining containment cooling.

The M-series tests that test MSLB conditions covered a broad spectrum of the test parameters expected in the SBWR (which are similar to the ESBWR test parameters) to investigate the long-term cooling phase of a LOCA. The PCCS performed well, maintaining adequate containment cooling in the MSLB test. Drywell air was purged to the wetwell by means of the PCCS. There was a smooth transition from the GDCS injection phase to the long-term cooling phase. The VB openings in a test did not significantly affect the global drywell and pressure response, as compared to a similar test without the VB openings.

Although the PANDA M-series data are for the MSLB test conditions, the containment phenomena in the long-term cooling phase of other LOCAs, such as the GDCSLB, BDLB, and FWLB, are generally similar to those of the MSLB (with an exception to be discussed below). This is because, before the start of the long-term cooling phase (with variations in the starting time, which is LOCA dependent), the RPV has depressurized from the ADS actuation and the GDCS injection has become insignificant. However, there was one exception. As stated above, the potential opening of the GDCS equalizing lines to provide SP water to the RPV could not be investigated in the PANDA test facility. (See the previous discussion of RAI 21.5-1.)

As stated earlier, the PANDA M-series tests were based on the SBWR design, which is very similar to the ESBWR design in terms of the RPV and containment phenomena expected in a LOCA. Furthermore, the design changes from the SBWR to the ESBWR did not introduce new phenomena. Equally important, the phenomena observed in the PANDA M-series tests were generally understood and appeared to be reasonable. For example, the addition of relatively cold water at room temperature to the PCCS pools temporarily enhanced the overall PCCS heat removal rate and could lead to VB opening. However, this did not significantly affect the overall behavior of the drywell and wetwell pressures. Therefore, the staff concluded that the PANDA M-series tests provided a valid database to qualify the TRACG code for the long-term cooling phase of a LOCA relevant to the ESBWR LOCA events.

PANDA P-Series Tests

The test objectives were to (1) reinforce the existing database to confirm the adequacy of TRACG to predict the ESBWR containment performance, including potential systems interaction effects, and (2) confirm the performance of an earlier preapplication version of the ESBWR containment configuration with the GDCS gas space connected to the wetwell gas space.

In the current ESBWR design as submitted for design certification, GEH modified the design by moving the connections of the GDCS pool airspace from the wetwell back to the drywell and eliminating the connecting vent between the wetwell airspace and the GDCS pool airspace. Therefore, this configuration is the same as the arrangement in the SBWR design and in the integral systems test programs, PANDA M-series and GIRAFFE, used for qualification of the TRACG code. Containment volumes were adjusted along with this change to ensure the wetwell-to-drywell volume ratio and thus retain most of the benefit of the reduced containment pressure that was gained when this GDCS airspace volume was originally moved from the drywell to the wetwell. While the earlier (preapplication version) ESBWR configuration provided additional margin in the containment pressure performance, it resulted in several complicating design issues necessitating that GEH implement this modified ESBWR configuration, which is similar to the original SBWR configuration.

PANDA is a large-scale integral test facility originally designed to model the long-term cooling phase of a LOCA for the SBWR. It has all the major components, including the RPV, drywell, wetwell, and GDCS pool. The RPV was equipped with electrical heaters and heater controls to

simulate decay heat and the release of RPV stored energy. The facility included all three scaled PCCS heat exchangers and one ICS unit and their associated water pools. Other components represented in PANDA include VBs between the drywell and the wetwell and the equalizing lines between the SP and the RPV.

The RPV was modeled using a single vessel in PANDA, while the drywell and wetwell were modeled using two pairs of vessels, connected by large pipes. This double-vessel arrangement permitted investigation of spatial distribution effects within the containment volumes. The water in the RPV was heated by a bank of controlled electrical heaters that could be programmed to match the decay heat curve. Main steamlines conveyed boiloff steam from the RPV to the two drywell vessels. The PCCS and ICS inlet lines were connected to the drywell and RPV, respectively. Drainlines from the lower headers of the PCCS and ICS units returned condensate to the RPV. Ventlines from the lower headers of the PCCS and the upper and lower headers of the ICS were at prototypical submergences in the SP. VBs were located in the lines connecting the drywell and wetwell gas spaces. PANDA had the capability to valve out one of the main steamlines, the ICS, and individual PCCS. It also had the capability to inject noncondensable gas (air or helium) into the drywell over a prescribed time period during the post-LOCA transient tests.

As stated above, in the original PANDA/SBWR configuration (for the PANDA M-series tests), the GDCS gas space was connected to the drywell. A major modification made in the PANDA/SBWR was to connect the GDCS gas space to the wetwell gas space (for the PANDA P-series tests) to model a preapplication version of the ESBWR configuration. This ESBWR configuration, which was not adopted as the final ESBWR design, provided a larger volume for the noncondensable gases that are purged from the drywell to the wetwell during the blowdown phase and therefore reduced the containment pressure. In its original configuration for the SBWR, PANDA was a 1/25-volume-scaled, full-height representation of the SBWR primary system and containment. As configured for the P-series tests for the ESBWR, the PANDA facility was a full-height representation of the ESBWR containment at a nominal volumetric scale of 1:45. The piping interconnecting the PANDA vessels was scaled (primarily with the use of orifice plates) to produce the same pressure loss as the corresponding ESBWR piping. The three PANDA PCCS units were approximately equivalent to the four ESBWR PCCS units, and the one PANDA ICS unit was about 10-percent underscaled relative to the four ESBWR ICS units.

The tests investigated the integral systems response of the RPV, drywell, and wetwell for the late GDCS injection phase and the long-term cooling phase of the MSLB. PCCS performance in maintaining containment cooling was also assessed.

As stated earlier, the PANDA P-series tests were based on a preapplication version of ESBWR configuration, in which the GDCS pool was isolated from the drywell and its gas space was connected to the wetwell gas space instead of the drywell, as in the SBWR and the current ESBWR configuration. In addition, the PCCS drainlines were connected to the RPV instead of the GDCS pool, as in the SBWR and the ESBWR. The P-series tests consisted of eight integral systems tests for the MSLB (which was expected to be the most challenging LOCA to the containment for the SBWR) to investigate the containment response and phenomena during the long-term cooling phase under various initial and boundary conditions. PCCS performance was successfully demonstrated to maintain containment cooling. Various containment phenomena were investigated. The changes noted made the PANDA-P tests consistent with the preapplication version of the ESBWR configuration with minor deviations.

Like the PANDA M-series tests, the PANDA P-series tests were conducted in the same facility except with modifications necessary to conform to a preapplication ESBWR configuration as stated earlier. There was no lower drywell, and other LOCAs with a lower break location, such as the GDCSLB and BDLB, could not be tested. Tests did not investigate potential openings of the SP equalizing lines to provide SP water to the RPV.

The PCCS pools in PANDA were much smaller than the scaled volume. For tests longer than about 35,000 seconds (9.7 hours), the PCCS condenser tubes were uncovered unless water was added to the pool from an outside source.

The PANDA facility has all the necessary components to conduct the integral systems tests for a design-basis LOCA, such as an MSLB. The P-series tests covered a broad spectrum of the test conditions expected in the ESBWR to investigate the long-term cooling phase of a LOCA. The PCCS performed well and maintained adequate containment cooling in the MSLB tested. The transition was smooth from the late GDCS injection phase to the long-term cooling phase. Injection of a noncondensable gas (either air to simulate nitrogen or helium to simulate hydrogen) to the drywell degraded the PCCS performance. The PCCS was capable of purging noncondensable gas from the drywell to the wetwell, as it was injected.

At a low decay heat equivalent to several hours into the MSLB, the test data suggested that the PCCS was capable of maintaining containment cooling even when the PCCS condenser tubes were substantially uncovered.

Although the PANDA P-series data are for the MSLB application, the containment phenomena in the long-term cooling phase of other LOCAs, such as the GDCSLB, BDLB, and FWLB, are generally similar to those of the MSLB. The reason is, before the start of the long-term cooling phase, the RPV has depressurized from the ADS actuation. As stated earlier, the PANDA tests could not investigate the potential opening of the SP equalizing lines to provide SP water to the RPV. (See the previous discussion of RAI 21.5-1.)

Some of the data have revealed distortions (e.g., a temperature rise in the wetwell gas space from nonprototypical heating from the gas flow in the vertical main vent pipe until it was valved out). These nonprototypical distortions are not expected to change the overall containment behavior. The phenomena observed in the PANDA P-series tests are generally understood and seem to be reasonable. For example, when a VB opened, some of the wetwell noncondensable gas flowed to the drywell and degraded the PCCS performance. As a result, the drywell pressure first rose and eventually leveled off when the pressure difference between the drywell and the wetwell was sufficient to overcome the PCCS vent submergence and vent pipe flow resistance. As expected, main vents cleared (to vent the drywell gas directly into the wetwell) when there was insufficient heat removal in the PCCS as a result of either the absence of one PCCS unit (out of a total of three) or noncondensable gas injection to the drywell during a test.

On the basis of the preceding discussion, the staff concludes that, despite the difference in containment configuration between the PANDA P-series tests and the current ESBWR, the PANDA P-series tests provided a valid database to confirm the qualification of the TRACG code for the long-term cooling phase of a LOCA relevant to the ESBWR LOCA events; in particular, the tests provided data on PCCS performance with noncondensable gas at an additional scale.

21.5.3.3 Summary of the ESBWR Component and Integral Systems Testing Programs

The results of the Single Tube Condensation Test Program performed at UCB were the basis for the condensation heat transfer correlation used in the TRACG code. The full-size component test data from the PANTHERS/PCCS and PANTHERS/ICS test programs cover the range of the operational conditions expected in the design-basis LOCAs in the ESBWR. These data are adequate for validating the TRACG code regarding the PCCS and ICS performance in the ESBWR (with the understanding that a PCCS condenser in the ESBWR has approximately 35-percent more heat removal capability than does the PANTHERS/PCCS condenser, and an ICS condenser has twice the heat removal capability as the single-module PANTHERS/ICS condenser).

The integral systems test data from the GIST, GIRAFFE/helium, GIRAFFE systems interactions, PANDA M-series, and PANDA P-series testing programs as a whole cover a range of the late blowdown phase, GDACS phase, and long-term cooling phase of the accidents. The staff understood the phenomena revealed in the data and concluded that the weaknesses (including some phenomenon distortions) in general do not invalidate their overall applicability to the reactor vessel and containment responses in a LOCA. The combined data from the GIST, GIRAFFE, and PANDA integral systems tests covered the LOCA phenomena and processes defined in the PIRTs for the late blowdown phase, GDACS phase, and long-term cooling phase.

Each integral systems test provided a set of “valuable” data on the time-dependent, thermal-hydraulic response of the RPV, drywell, and wetwell with the operation of the GDACS, PCCS, or ICS in a LOCA. For the TRACG code to properly simulate the test, the code must have technically sound conservation equations, including the constitutive package and numerics. As a result, the data of an integral systems test are useful for assessing a code against the test for the specific test configuration and initial and boundary conditions. However, to link the integral systems test data to the ESBWR response in a LOCA required an adequate scaling analysis to demonstrate the applicability of the test data to the ESBWR response. GEH performed such a scaling analysis, and the staff evaluated it, as discussed below.

In conclusion, the staff has reviewed and evaluated the test programs performed originally in support of the GEH SBWR design and finds the testing to be applicable to the ESBWR design, based on the PIRT and scaling analysis as discussed below. Based on the design description for the ESBWR provided in DCD Tier 2, Revision 9, the staff also concludes that no further testing in support of LOCA thermal-hydraulic behavior of the design is necessary.

21.5.3.4 Determination of Effect of Scale

Various physical processes may give different results as components or facilities vary in scale from small to full size. The quantification of bias and deviation must include the effect of scale to determine the potential for scaleup effects.

GEH used the hierarchical two-tier scaling (H2TS) process. One of the key elements of the H2TS approach is the identification of the important physical phenomena governing a process. Generally, the phenomena are identified and ranked in importance, and the results of this effort are documented in a PIRT. The H2TS approach consists of a top-down method, which is a system scaling analysis used to derive scaling groups and establish a scaling hierarchy, and a bottom-up method, which focuses on the important processes and introduces similitude to ensure that the scaled test data are applicable to the prototype. The top-down system scaling does not replace, but rather provides a rational framework for, the bottom-up scaling.

NUREG/CR-5809, "A Hierarchical Two-Tiered Scaling Analysis," issued November 1991, describes the H2TS approach.

Evaluation of the GEH Scaling Analyses

To evaluate the adequacy of the GEH scaling approach, the objectives of a scaling analysis for code assessment were defined and that definition was used to evaluate how the GEH ESBWR scaling report NEDC-33082P, "ESBWR Scaling Report," Class III, issued December 2002, demonstrated that the objectives were accomplished. NEDC-33082P defined the objective as "to show that the test facilities properly 'scale' the important phenomena and processes identified in the ESBWR PIRT and/or provide assurance that the experimental observations from the test programs were sufficiently representative of ESBWR behavior for use in qualifying TRACG for ESBWR design basis calculations." The staff accepted the objective as stated in the GEH report.

GEH adopted the H2TS approach for the ESBWR. The LOCA served as the basic event for the scaling analysis. Since the importance of the governing phenomena changes as the event unfolds, GEH defined four accident phases that span the accident, namely, late blowdown, GDCS initiation, GDCS phase, and PCCS phase. The early blowdown period is not significant for passive safety system performance and was therefore ignored. The primary test facilities scaled for SBWR and ESBWR testing can simulate decay power levels starting at approximately 1 hour after the initiation of the accident. Since a key issue is PCCS performance, the scaling was directed at the late blowdown phase extending into the long-term cooling phase. The long-term cooling phase is unique to the SBWR/ESBWR containment because of the substitution of passive for active cooling systems.

GEH began its scaling efforts with a PIRT. The top-down scaling approach complements the PIRT by identifying the important phenomena during each accident phase based on nondimensionalization of the governing equations. The global momentum and energy conservation equations used were based on the lumped-parameter approach. The system was divided into several large volumes. The equations of energy and mass balance developed for a generic volume were then applied to each of these volumes at different time periods during the transient. The equations were made nondimensional and the resulting nondimensional coefficients were defined as the "Pi's" (Pi groups are defined as similarity numbers derived from the conservation equations applicable to the system of interest. Pi groups are dimensionless, and are used as model scaling criteria.) to represent the relative importance of the participating phenomena.

The bottom-up scaling considered the individual phenomena at a local level. GEH used bottom-up scaling to look in more detail at specific processes important to system behavior. For the ESBWR, the analysis identified 46 highly ranked phenomena needing detailed evaluation and providing the basis for acceptability of the data for TRACG qualification.

The main objective of integral scaled facilities was to capture not only the component behavior, but also its dynamic interactions as a complete system. NEDC-33082P acknowledged this in the executive summary, which states that "[a] comprehensive experimental program was carried out to demonstrate the thermal-hydraulic performance of these passive systems and their components." The staff, however, noted that the analysis presented in the report did not account for systems interactions. The staff believes that, while one cannot expect that any of the scaled facilities represents a simulation of the prototype, for completeness, they must at least exhibit the same kind of interactions between components and subsystems as expected of

the prototype. It is up to the scaling analysis, therefore, to determine the relevancy of these interactions. System interactions are not explicitly called out in the PIRT as phenomena. They are, however, an integral part of the transient, and they determine the sequence of events that define the beginning of a phase, the end of a phase, and the process that controls the state of the system during that phase.

In general, the reactor system was divided into subsystems for which governing equations were developed. The governing equations were made nondimensional by referring all variables to a set of norms or reference parameters (including a reference time), according to the purpose of the analysis. The intent of this process was to obtain nondimensional parameters. The nondimensional coefficients of these equations, the system Pi's, contain information about how the different components of the system interact and which of these many interactions dominates the transient behavior during a given phase.

During each transient, the system state and its configuration changes as the transient progresses from one phenomenologically distinct phase to the next. Each of these phases will include a process or a set of competing processes that define the beginning and the end of the phase and therefore its reference time. The general approach needs to be repeated for each system configuration and each reference time.

The top-down scaling should reach a certain level of system detail. At one extreme, the approach could assume that the entire reactor system is one comprehensive volume and conduct the analysis accordingly. The result would be simple and of limited value. At the other extreme, the approach would call for as much detail as possible, without invoking multidimensional effects or the local distribution of a phenomenon. The latter would likely result in a system representation that varies from phase to phase of the transient, as the system configuration varies (valves open and close, tanks empty or fill).

GEH selected an in-between approach and identified the major system volumes as the components, all represented in principle by the same equations of energy and mass conservation. The momentum equations of the connecting lines or paths were neglected as having no dynamic contribution. Furthermore, NEDC-33082P, Section 6.2, cited previous efforts by stating, "Results from the SBWR work showed that there are no significant interactions in the SBWR system or the related tests and no new Pi numbers resulted." The staff, however, believes that the SBWR study presented in NEDC-32288P found that the lines and connecting paths have very fast response times compared to other simultaneous processes and that they contribute enough damping to suppress oscillations. The last paragraph of Section 6.2 suggests that the analysis conducted for the SBWR was not carried out for the ESBWR because the designs are "similar enough." However, the staff believes that in both the SBWR and ESBWR, the volumes do interact because they are connected. In response to the staff request, GEH addressed this deficiency by performing a revised scaling analysis as discussed later in this section.

The statement in NEDC-33082P, Section 6.3, that "these equations are applied to the specific regions of the ESBWR" raised the question of whether the GEH original scaling approach ignored interactions. Even when two or three volumes were actively participating and interacting with each other, the GEH approach addressed the volumes independently in NEDC-32288P and NEDC-33082P. The staff believes that the volume equations (mass and energy) have terms that represent inflows and outflows. In most cases, these are not external inputs to the reactor system, but result from gradients between connecting volumes and, therefore, are not independent variables. A single volume equation can neither capture nor describe this

system behavior and is insufficient to draw conclusions about that behavior. It is likely that the two or three volumes involved were interdependent and could be represented by a single equation. As a result, the staff concluded that the equation used by GEH in its analysis was not capable of demonstrating system interactions. In fact, the GEH original scaling approach in NEDC-32288P and NEDC-33082P considered no analysis of system interactions.

The nondimensional coefficients, or Pi groups, identified in the top-down scaling are more complex than the more traditional similarity parameters derived in the study of physical phenomena, such as the Reynolds number and Prandtl number. Evidence of this complexity is the fact that a characteristic system time is an integral part of these Pi groups and they come in sets of two or more. The Pi groups are derived from the macroscopic analysis of distinct elements of the system that accounts for the way in which the elements interact and exchange mass, energy, or both with each other and with the environment. These Pi groups are a useful tool to determine what processes or mechanisms dominate the behavior for each particular system. They can also be used to assess whether two different systems can be expected to behave similarly. However, the similarity can only be guaranteed a priori if the two systems have identical Pi groups. If the Pi group values differ, further analysis is necessary to assess the similarity between the different systems. The most important part of this further analysis is the verification that the data—and code calculation for the test facility—exhibit the same trends, magnitudes, and variations in nondimensional space. The other aspect of this analysis is the evaluation of local phenomena to ensure that, while the systems are expected to be similar in their macroscopic behavior, the local phenomena (bottom-up) support this expectation by producing the same regime. This invokes the more traditional nondimensional groups, such as Reynolds, Prandtl, and Biot numbers, which correspond to the local processes not captured by the top-down formulation of the system equations. The GEH scaling report, NEDC-33082P, in its original version, was very weak in this area because it did not produce these analyses; instead, it relied on an arbitrary range of Pi groups for similarity assessment. As a result, the staff requested that GEH submit additional information to address the concerns identified above.

GDCS Transition Phase

In RAI 6.3-1, the staff asked GEH to perform a revised scaling analysis for the 4,500-megawatt-thermal (MWt) ESBWR addressing the deficiencies, as discussed above, including calculating revised Pi values using interconnected volumes and components, and to use the updated ESBWR design values in the analysis.

In response, GEH updated the ESBWR scaling analysis. In the new analyses, GEH updated the ESBWR power level and design. In addition, GEH addressed deficiencies in the original scaling approach using new equations that accounted for the interactions between volumes. The system Pi's that resulted from the updated analysis differed significantly from the system Pi's from the noninteracting equations that GEH used in its original analyses.

Moreover, GEH successfully applied the equations to the GDCS transition phase, which is the onset of GDCS injection—the period when the minimum vessel inventory occurs in a LOCA. In the updated analysis, GEH abandoned the arbitrarily defined range of Pi groups and conducted a rigorous analysis for the GDCS transition phase, where the largest difference in Pi groups was observed. This confirmatory scaling analysis was based on a simplified model for a BWR depressurization transient as documented in the article by M. di Marzo, “A Simplified Model of the BWR Depressurization Transient,” Nuclear Engineering and Design, 205 (2001), pp. 107–114, July 28, 2000. The results showed that, although the variations in Pi groups between the ESBWR and test facilities approached the 1/3 to 3 range, the variations in the pressure and

liquid mass responses had a small impact on the figure of merit (minimum RPV liquid inventory, the most critical variable) compared to the margin to the design limit (core uncover). This confirmed that the experiments behaved qualitatively the same as their scaling model and the TRACG ESBWR model.

Because GEH used the GDCS injection line break in its earlier analyses for the 4,000-MWt ESBWR, it also used the same GDCS injection line break for the 4,500-MWt ESBWR as an example in the updated analysis to allow a comparison of the results.

GEH also presented the results for the 4,500-MWt ESBWR for the base case (with standby liquid control system [SLCS] flow) and another case without the SLCS injection during the late blowdown and the GDCS transition phases. The results showed that the SLCS injection helps keep the water inventory at a higher level until the GDCS injection begins. However, the SLCS injection has only a small effect on the vessel depressurization rate and thus on the timing of the GDCS initiation, which occurs when RPV pressure reaches the pressure at which GDCS injection begins. Also, the calculated values of Pi groups for the late blowdown phase showed that the contribution from the SLCS flow rate is small compared to that from the ADS flow rate, which dominates the RPV depressurization rate; however, the SLCS flow rate is significant from the viewpoint of RPV liquid inventory. In addition, the ICS and control rod driveline flows were neglected because they are small compared to the break, ADS, SLCS, and GDCS flows.

The GEH results show that the behavior of the 4,500-MWt ESBWR during the late blowdown and GDCS injection phases is expected to be very similar to that observed in the GIRAFFE/SIT and GIST tests. Thus, GEH stated that no additional tests were required for scaling of the 4,500-MWt ESBWR for these phases.

The staff finds the GEH response acceptable.

Long-Term Cooling Phase

The ESBWR system encompasses two major energy sinks—the SP and the PCCS pool. The SP is the primary sink in the initial portion of the transient. The PCCS pool takes over in the long-term portion of the transient. The transition from heat deposition in the wetwell to heat deposition in the PCCS pool is a fundamental element of the ESBWR system.

GEH scaled and designed the systems test facilities in such a way that few data on multidimensional phenomena were obtained. Analysis of the system test data was based on a lumped-parameter approach that eliminated multidimensional spatial variations in the containment. As such, the tests did not provide sufficient data to credit multidimensional effects. Since the data were not suitable to qualify TRACG to predict multidimensional effects, TRACG is not qualified for multidimensional effects in the ESBWR analysis.

In RAI 6.3-1, the staff requested that GEH compare the revised ESBWR Pi values with those obtained from the tests for the LOCA phases.

In response, GEH provided comparisons of revised values of Pi groups between the ESBWR and the tests for all the phases of LOCA. The Pi values were within an acceptable range (1/3 to 3).

GEH did not provide any confirmatory scaling analysis for the phases of LOCA, except for the blowdown and GDCS transition phases. Therefore, in a supplement to RAI 6.3-1, the staff

requested that GEH explain why it considered confirmatory scaling analysis similar to the approach taken for the late blowdown and GDCS transition phases to be unnecessary for other phases of LOCA, including the long-term cooling phase.

In response, GEH stated that the purpose of the simplified confirmatory scaling analysis for the late blowdown and GDCS transition phases was to show that the pair of differential equations that govern the RPV transient pressure and liquid inventory could be simplified and solved numerically to directly demonstrate similar responses for the ESBWR and the test facilities. In the process, the key phenomena that govern the relatively rapid changes in the RPV pressure and liquid inventory during these phases of the LOCA transient were identified and clarified. This situation is in marked contrast to the long-term cooling (PCCS) phase of the LOCA transient where pressures in the RPV, drywell, and wetwell are essentially equal, and changes occur in a quasi-static manner.

GEH further stated that the steam generation rate inside the RPV is directly proportional to the decay heat and the entire amount of steam discharges into the drywell through the break and the ADS. The steam discharge rate is independent of the type of break, and the RPV and the drywell are effectively uncoupled. The decay heat steam, along with a small amount of residual drywell noncondensable, flows into the PCCS, which is submerged in the PCCS pool above and outside the containment. The steam is condensed in the PCCS tubes, and the condensate flows into the GDCS pool. The residual drywell noncondensable eventually moves to the wetwell gas space and causes a small pressure increase. GEH also stated that, during the long-term cooling phase, as shown in DCD Tier 2, Revision 9, Figure 6.2-11, the PCCS is capable of transferring all the decay heat to the PCCS pool outside the containment. Therefore, there is no further heatup of the wetwell pool and no wetwell gas space pressure increase from steam generated in the RPV because of decay heat. Hence, the only coupling between the drywell/PCCS and the wetwell can be taken into account by considering eventual transfer of all drywell noncondensables to the wetwell. As a consequence, GEH concluded that, by considering transfer of all drywell noncondensables to the wetwell, the containment pressure would be conservatively bounding. The staff agrees with this conclusion. However, the staff also believes that potential trapping and delayed release of enough drywell noncondensables can adversely impact PCCS performance and containment pressure during the long-term cooling phase and therefore should be considered when calculating the conservatively bounding containment pressure. In addition, the staff agrees with the GEH statement that the minimal coupling between the different regions during the long-term phase means that the Pi groups for the wetwell and the drywell can be evaluated separately without reference to the other regions.

Based on the considerations that the containment pressures will be calculated on the basis of a bounding approach and that the Pi values are within an acceptable range, GEH concluded that no additional or confirmatory scaling analysis is required for the long-term cooling phase. Based on the applicant's response as described in the preceding paragraphs, RAI 6.3-1 is resolved.

21.5.3.5 Summary of GEH Scaling Analyses

The GEH scaling analyses demonstrated that the test facilities were scaled properly for their intended purpose. All the test facilities met the top-down scaling criteria. However, the power-to-volume scaling approach introduced scaling distortions related to structural heating/cooling, aspect ratio, and geometrical complexity. GEH identified and evaluated these distortions. The staff concluded that the analyses included the essential phenomena that are expected to occur

in the ESBWR design and that the experimental results were appropriate for TRACG qualification.

The distortions, as identified by GEH, were caused by heat transfer from RPV structures, heat transfer to and from the drywell and wetwell structures, and drywell three-dimensional effects, including drywell mixing, noncondensable gas stratification, and buoyancy/natural circulation. GEH developed bounding models to address these three-dimensional effects such that TRACG is able to adequately predict the effects. The staff further concluded that the data from the GIRAFFE and the PANDA facilities can be used for scaleup to the ESBWR through the TRACG code. Based on this evaluation, the staff concluded that the TRACG model used for the containment/LOCA evaluation can be conservatively biased.

The staff concluded that GEH demonstrated that relevant and sufficient data exist to qualify TRACG in its simulation of the phase for which the scaling analysis was completed. The phase for which this was done, the GDCS injection phase, is indeed the most important period of the transient. The staff, however, recognizes that there are deficiencies in the GEH scaling analysis for the long-term cooling phase, particularly regarding the system interactions, the energy partition between the SP and PCCS pools, and the effect of containment structures. However, GEH can employ conservative, bounding analyses for the long-term cooling phase to overcome these deficiencies.

The staff, therefore, finds the GEH scaling analyses acceptable.

21.5.3.6 *Compliance with 10 CFR 52.47, “Contents of Applications; Technical Information,” Requirements*

The ESBWR meets the requirements delineated in 10 CFR 40.43(e) as referenced by 10 CFR 52.47(b)(2)(c)(2) and discussed below.

ESBWR plant features appeared in earlier BWR designs which have provided satisfactory operation over many combined plant operating years of service. While the details of the particular plant feature design for the ESBWR may differ somewhat from those in current plants, the function of each feature is substantially the same. For those ESBWR safety features considered unique, GEH used separate effect test programs to demonstrate their performance. The operating plant experience and the ESBWR-specific separate effect test programs constitute a sufficient database to meet the requirements of 10 CFR 50.43(e)(1)(i).

GEH used integral test programs to demonstrate the acceptability of system interactions for features that are unique to the ESBWR (i.e., ICS, GDCS, and PCCS). For features that are not unique to the ESBWR, operating plant experience is applicable. The operating plant database and the ESBWR integral test program data are sufficient to meet the requirements of 10 CFR 50.43(e)(1)(ii) and (iii).

ESBWR feature performance was predicted with the TRACG computer code. TRACG was qualified by a comparison of data from ESBWR-specific separate effect and integral test programs to data from operating BWRs over a wide range of reactor conditions, including temperatures and pressure conditions in which the features are expected to operate. The TRACG analyses add to the confidence that the features would perform as expected and that the requirements of 10 CFR 50.43(e) have been met.

21.5.4 Conclusions

The full-size component test data from the PANTHERS/PCCS and PANTHERS/ICS testing programs cover the range of operational conditions expected in the design-basis LOCAs in the ESBWR. These data are adequate for validating the TRACG code regarding the PCCS and ICS performance in the ESBWR, with the understanding that a PCCS condenser in the ESBWR will have approximately 35-percent more heat removal capability than that of the PANTHERS/PCCS condenser, and an ICS condenser (with two identical modules of tubes) has twice the heat removal capability as the PANTHERS/ICS condenser (with only one module of tubes).

The integral systems test data from the GIST, GIRAFFE/helium, GIRAFFE systems interactions, PANDA M-series, and PANDA P-series test programs as a whole cover a range of the late blowdown phase, GDACS phase, and long-term cooling phase of the accidents. Strengths and weaknesses of the individual test programs were identified and evaluated. The staff has reviewed the test programs and results and concludes that the weaknesses (including some phenomenon distortions) in general did not invalidate their overall applicability to the reactor vessel and containment responses in a LOCA simulated by TRACG. The combined data from the GIST, GIRAFFE, and PANDA integral systems tests are generally expected to cover the LOCA phenomena and processes defined in the PIRTs for the late blowdown phase, GDACS phase, and long-term cooling phase.

Furthermore, GEH demonstrated that relevant data are sufficient to qualify TRACG in its simulation of the phase for which the scaling analysis was completed. The phase for which this was done, the GDACS injection phase, is indeed the most important period of the transient. GEH employed conservative, bounding analyses for the remainder of the LOCA event.

On the basis of the above discussion, the staff concludes that GEH has met the requirements of 10 CFR 50.43(e) and that no further testing in support of the LOCA thermal-hydraulic behavior for the ESBWR design is necessary.

21.6 TRACG Analysis Methods for the ESBWR

GEH uses the TRACG thermal-hydraulic code to perform design-basis analyses of the ESBWR. The analysis code and methods for each application are described in the following topical reports:

- Large- and small-break LOCA and containment analysis is described in Sections 2 and 3 of NEDC-33083P-A, "TRACG Application for ESBWR," March 2005 and NEDC-33083P-A, Revision 1, "TRACG Application for ESBWR," September 2010.
- Stability analysis is described in NEDE-33083P-A, Supplement 1, Revision 2, "TRACG Application for ESBWR Stability," September 2010.
- ATWS analysis is described in NEDE-33083P-A, Supplement 2, Revision 2, "TRACG Application for ESBWR Anticipated Transient Without Scram Analyses," October 2010.
- Non-LOCA transients, including anticipated operational occurrences (AOOs) and infrequent events (IEs), are described in NEDE-33083P-A, Supplement 3, Revision 1, "TRACG Application for ESBWR Transient Analysis," September 2010.

During the preapplication review of the ESBWR, the staff reviewed and approved NEDC-33083P-A for the use of TRACG as an acceptable evaluation model for the LOCA and containment design-bases analyses. NEDC-33083P-A refers to the staff's evaluation and includes 20 "confirmatory items" that were identified as needing resolution at the design certification stage. The staff's "Addendum to the Safety Evaluation Report for NEDC-33083P-A, Application of the TRACG Computer Code to the ECCS and Containment LOCA Analysis for the ESBWR Design," dated September 20, 2010, addresses the evaluation of the 20 confirmatory items.

The staff reviewed and approved NEDE-33083P, Supplement 1, for the use of TRACG as an acceptable evaluation model for the ESBWR stability analysis. The NRC letter "Reissuance of Safety Evaluation Report Regarding the Application of the GE-Hitachi Nuclear Energy Americas LLC (GEH) Licensing Topical Report (LTR) 'TRACG Application for the ESBWR Stability Analysis,' NEDE-33083P, Supplement 1," dated August 29, 2007, documents the staff's evaluation and includes confirmatory items that were identified as needing resolution at the design certification stage. The staff's "Addendum to the Safety Evaluation Report by the Office of New Reactors Application of the TRACG Computer Code to Thermal-Hydraulic Stability Analysis for the ESBWR Design NEDE-33083P, Supplement 1," dated September 13, 2010, addresses the evaluation of the seven confirmatory items.

The staff reviewed NEDC-33083P-A, Section 4, "Transient Analysis." The staff's "Safety Evaluation Report with Open Items for the Application of the TRACG Computer Code to the Transient Analysis for the ESBWR Design," dated April 2, 2008, documents the staff's evaluation. Subsequently, GEH submitted NEDE-33083, Supplement 3, to document the TRACG application to AOOs for ESBWR. The open items from the staff's review of NEDC-33083P-A Section 4, "Transient Analysis," are addressed in detail and closed, and the updated information in NEDE-33083, Supplement 3, is addressed in the "Safety Evaluation for the TRACG Application for ESBWR Transient Analysis NEDE-33083P, Supplement 3, Revision 1," dated September 14, 2010.

The staff reviewed NEDE-33083P, Supplement 2, and documented its evaluation in the "Safety Evaluation with Open Items by the Office of New Reactors, Application of the TRACG Computer Code to Anticipated Transients Without Scram for the ESBWR Design NEDE-33083P, Supplement 2," dated April 2, 2008. The open items from the staff's safety evaluation are addressed in detail and closed in the "Safety Evaluation by the Office of New Reactors 'TRACG Application for ESBWR Anticipated Transients Without Scram Analyses,' NEDE-33083P, Supplement 2, Revision 2," dated October 20, 2010.

Although the full details of the staff's evaluation, including limitations and conditions of the TRACG code as applied to ESBWR design-basis analyses, can be found in the above references, the following sections document adherence to NRC regulations for the TRACG code for purposes of approving the ESBWR DCD.

21.6.1 Regulatory Basis

To establish a licensing basis, licensees must analyze transients and accidents in accordance with the requirements of 10 CFR 50.34, 10 CFR 50.46, and where applicable, NUREG-0737, "Clarification of TMI Action Plan Requirements," issued November 1980.

The staff reviewed the TRACG code based on the review guidelines of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants:

(LWR Edition),” referred to hereafter as the standard review plan (SRP), Section 15.0.2, issued December 2005.

The staff performed a comparison of the SRP version used during the review with the 2007 version of the SRP. The 2007 version did not include any requirements, generic issues (GIs), bulletins (BLs), generic letters (GLs), or technically significant acceptance criteria beyond those identified in the version used by the staff. Therefore, the staff finds that the use of SRP, Section 15.0.2, issued December 2005 acceptable for this review.

21.6.2 Summary of Technical Information

The following sections summarize the technical information needed to evaluate the analysis codes in accordance with the guidance in SRP Section 15.0.2.

21.6.2.1 Documentation

The development of an evaluation model for use in reactor safety licensing calculations requires substantial documentation.

SRP Section 15.0.2 requires that this documentation cover (1) the evaluation model, (2) the accident scenario identification process, (3) the code assessment, (4) the uncertainty analysis, (5) a theory manual, (6) a user manual, and (7) the QA program. The following list describes the documentation that GEH provided:

- Evaluation model description and theory manual (NEDE-32176P, Revision 4, “TRACG Model Description,” dated January 31, 2008)
- Licensing topical reports (LTRs) that cover accident scenario identification and uncertainty analysis
 - NEDC-33083P-A for LOCA
 - NEDE-33083P, Supplement 1 for stability
 - NEDE-33083P, Supplement 2 for ATWS
 - NEDE-33083P, Supplement 3 for anticipated operational occurrences (AOO)/ infrequent events (IE)
- Code assessment
 - NEDE-32177P, Revision 3, “TRACG Qualification,” dated August 29, 2007.
 - “Update of ESBWR TRACG Qualification for NEDC-32725P and NEDC-33080P, “Using the 9-Apr-2004 Program Library Version of TRACG04,” dated June 2, 2004.
 - NEDC-32725P, Revision 1, “TRACG Qualification for SBWR,” dated August 2002.
 - NEDC-33080P, “TRACG Qualification for ESBWR,” dated June 2, 2004.
- User’s manual—UM-0136, Revision 0, “TRACG04A, P User’s Manual,” issued December 2005.

- QA program (see Section 21.6.2.6 of this report for discussion of the QA program)

21.6.2.2 Evaluation Model

An evaluation model is the calculation framework for evaluating the behavior of the reactor coolant system during a postulated accident or transient. It includes one or more computer programs and other information necessary to apply the framework to a specific transient or accident, such as mathematical models used, assumptions included in the programs, a procedure for treating the program input and output information, specification of those portions of the analysis not included in the computer programs, values of parameters, and other information necessary to specify the calculation procedure. Evaluation models are sometimes referred to as a licensing methodology.

21.6.2.3 Accident Scenario Identification Process

The accident scenario identification process is a structured process used to identify and rank the reactor component and physical phenomena modeling requirements based on (1) their importance to acceptable modeling of the scenario and (2) their impact on the figures of merit for the calculation. It is also used to identify the key figures of merit or acceptance criteria for the accident.

GEH has performed phenomena identification and ranking and summarized the results in PIRTs. Table 21.6-1 summarizes the PIRTs submitted by GEH for the ESBWR.

Table 21.6-1. ESBWR PIRTs.

SCENARIO	TABLE	REFERENCE
LOCA—short term (water level calculations)	2.3-1	NEDC-33083P
LOCA—long-term core cooling		DCD Appendix 6G
AOO/IE	2.3-3	NEDE-33083P, Supplement 3, Revision 1
Stability	2.3-5	NEDE-33083, Supplement 1, Revision 1
ATWS	2.3-4	NEDE-33083, Supplement 2, Revision 2

21.6.2.4 Code Assessment

The code assessment provides a complete assessment of all code models compared to applicable experimental data and/or exact solutions in order to demonstrate that the code is adequate for analyzing the chosen scenario. GEH provided assessment reports of the TRACG code for general and ESBWR-specific qualification in the following:

- NEDE-32177P, Revision 3, “TRACG Qualification,” issued August 2007.
- “Update of ESBWR TRACG Qualification for NEDC-32725P and NEDC-33080P Using the 9-Apr-2004 Program Library Version of TRACG04,” dated June 2, 2004.
- NEDC-32725P, Revision 1, “TRACG Qualification for SBWR,” dated August 2002.

- NEDC-33080P, “TRACG Qualification for ESBWR,” dated June 2, 2004.

21.6.2.5 Uncertainty Analysis

Uncertainty analyses are performed to confirm that the combined code and application uncertainty is less than the design margin for the safety parameter of interest when the code is used in a licensing calculation. The GEH licensing calculations using TRACG are best-estimate methodologies.

Table 21.6-2 summarizes the safety parameters calculated by TRACG for the ESBWR.

Table 21.6-2. Safety Parameters Calculated by TRACG.

PARAMETER	EVENT—PRIMARY (SECONDARY)
Reactor Vessel Water Level	LOCA (AOO/IE)
Decay Ratio	Stability
Critical Power Ratio	AOO/IE (Stability)
Vessel Pressure	AOO/IE, ATWS
Peak Cladding Temperature	ATWS
Suppression Pool Temperature	ATWS

GEH does not explicitly calculate the uncertainty in the reactor vessel water level for LOCA evaluations. Since all of the TRACG LOCA evaluations show that the core does not uncover during a LOCA, GEH performed the calculation using bounding assumptions instead.

Although different methods are used to evaluate the uncertainty for AOO/IE, ATWS, and stability, the uncertainty in the calculated safety parameter is evaluated by statistically combining the uncertainties for medium and/or highly ranked PIRT parameters. In addition to the statistically evaluated uncertainty, extra uncertainty is added in the decay ratio calculation for predicting stability margins by setting the acceptance criteria for the decay ratio at 0.8. An unstable condition would occur at a decay ratio of 1.0. By setting the acceptance criteria at 0.8, GEH allows for an additional uncertainty of 0.2 in the decay ratio calculations.

21.6.2.6 Quality Assurance Plan

The code must be maintained under a QA program that meets the requirements of Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,” to 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities.” The staff performed two audits of GEH’s QA plan. The first audit took place between October 16 and October 19, 2006, resuming between October 30 and November 3, 2006 (Summary of Audit for Nuclear Design Codes, October / November 2006). The second audit took place between December 11 and December 15, 2006, resuming between December 19 and December 20, 2006 (Summary of Exit Meeting Held on December 15, 2006 to discuss Staff’s Audit of TRACG Loss-of-Coolant Accident Analyses). The third audit took place between

December 15 and December 19, 2008 (Technical Summary (Including Exit Meeting Discussions) for the TRACG Computer Code).

GEH has procedures that meet the requirements of Appendix B to 10 CFR Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" for assuring the quality of its engineering computer programs (ECPs). These procedures specify such things as the types of documentation necessary, control of the change process, and the approval process for ECPs. A synopsis of these procedures follows.

GEH refers to an engineering computer program (ECP) that is approved for development as "Level 1." A "Level 2" ECP is an approved production program that is verified and documented for design applications or for technical activities used in developing design-related information. The Level 2 review process consists of two phases. In Phase 1, a review team determines the adequacy of the ECP models and specifications and the adequacy of the planned testing. In Phase 2, a review team performs a technical review and provides the final independent verification of the testing. As part of this review phase, GEH ensures that all open items are closed, confirms that the documentation is sufficient and complete, and performs licensing impact evaluations (for NRC-approved methodologies).

GEH uploads Level 2 codes into the program library, which GEH staff can then use for the stated design applications. These codes cannot be changed once they have attained Level 2 status. If GEH were to change the code or make error corrections, the code would no longer be considered a Level 2 ECP.

Under certain circumstances, GEH uses non-Level 2 ECPs for design tasks for a limited time. "Level 2R" is a specific status defined by GEH procedure in the Level 2 process, which may be applied to design tasks for a limited time. The QA approving official must still approve Level 2R codes.

At the time the NRC approved TRACG04 for application to ESBWR LOCA analysis (NEDC-33083P-A), GEH considered TRACG04 to be a Level 1 ECP. During the December 2006 audit of TRACG at GEH, the staff viewed documentation associated with the Level 2 review process for TRACG04. TRACG04A (the "A" designator refers to the Alpha VMS version) obtained Level 2R status on July 29, 2005, and Level 2 status on August 2, 2005. GEH uploaded the TRACG04A version that is Level 2 and is also used for ESBWR design calculations into the GEH program library on June 27, 2005. This corresponds to Version 52 of TRACG04A.

During the December 2006 audit, the audit team found that GEH controlled changes to TRACG04P PL 52 code under a level 2R code change control process to support code development that did not have QA controls for independent verification and validation (V&V) of code calculations. Considering planned model revisions disclosed during the audit, the final DCD revision (i.e., Revision 9) will likely be based on a later TRACG code revision that the staff has not reviewed. After changes to the TRACG04P code are complete, GEH is required to place the TRACG04 code under a QA-approved code change control process (such as Level 2) where independent V&V is performed in accordance with 10 CFR Part 50, Appendix B, Criterion III, "Design Control." In RAI 21.6-109, the staff requested that GEH inform the staff about placing the TRACG04 code under a QA-approved code change control process, and provide information to the staff sufficient for its use in reviewing and approving the version of TRACG04 used to develop the final DCD submittal. The staff was tracking RAI 21.6-109 as an open item in the SER with open items.

On December 15–19, 2008, the staff conducted an inspection at the GEH facility in Wilmington, NC. The inspection assessed GEH's compliance with selected portions of Appendix B to 10 CFR Part 50 and the provisions of 10 CFR Part 21, "Reporting of Defects and Noncompliance." During the inspection, the NRC inspectors found that implementation of GEH's QA program failed to document the justification for the use of a particular version of a non-Level-2 code during alternate calculations to verify original calculations and assumptions. Specifically, the staff noted that Appendix F to Global Nuclear Fuel Common Procedure 03-09, "Independent Design Verification," Revision 1, dated January 4, 2006, allows for use of several different versions of non-Level-2 code with appropriate justification. During the inspection, the staff did not find evidence that the use was justified, as there was no documentation concerning when non-Level-2 codes were used. At the end of the inspection, GEH prepared a Corrective Action Request (CAR 47253) to address this issue. This issue was identified as Notice of Violation (NOV) 05200010/2008-201-02 in Inspection Report 05200010/2008-201, dated March 25, 2009.

On April 23, 2009, GEH responded to NOV 05200010/2008-201-02 by stating that it had updated ESI 30-01, "Alternate Calculations for Verification of Non-Level-2 Computer Code Calculations," on March 23, 2009, to require written justification for use of a non-Level-2 version of the TRACG04 code when applied to all GEH and Global Nuclear Fuel analysis activities. In its response, GEH also committed to the performance of safety analyses for the DCD, Revision 6, and future revisions of LTRs NEDO-33337, "ESBWR Initial Core Transient and Accident Analysis," and NEDO-33338, "ESBWR Feedwater Temperature Operating Domain Transient and Accident Analyses," with the TRACG04P Level 2 ECP. As a result, non-Level-2 versions of TRACG will not be applied to future DCD analyses, alleviating the need for further discussion of the rationale concerning code versions. Based on the information in the GEH response, the staff determined that RAI 21.6-109 and NOV 05200010/2008-01-02 are resolved.

During the review of TRACG for ESBWR LOCA applications, GEH transitioned from TRACG02A to TRACG04. To support this review, GEH submitted the ESBWR-specific qualification cases using TRACG04. In this submittal, GEH updated NEDC-32725P, "TRACG Qualification for SBWR," and NEDC-33080P, "TRACG Qualification for ESBWR," by combining them into one document and performing the assessment cases using TRACG04. Most of the cases were run with the April 9, 2004, program library version of TRACG04A. This corresponds to Version 40. The team viewed all of the changes from Version 40 to Version 52 (i.e., the Level 2 version used for all ESBWR design certification calculations).

Although GEH performed part of the TRACG04 assessment with a different version of the code than the version it is using to license the ESBWR, the staff determined that the nature of the changes would not invalidate the qualification basis used to support the NRC's approval in NEDC-33083P-A and therefore finds the changes made to the TRACG04 code acceptable.

The staff found that GEH had submitted a code for NRC approval that had not completed the QA process (i.e., Level 1 or Level 2A). However, the staff verified that the executable used for TRACG04A had not been changed since June 27, 2005, and the QA was completed in August 2005. All ESBWR design certification analyses have been performed with this same TRACG04 source code. The staff found that overall the changes were insignificant and that the use of TRACG04 for ESBWR licensing applications complies with the intent of Step 4 of the code, scaling, applicability, and uncertainty methodology, "Frozen Code Version Selection" (NUREG/CR-5249, Revision 4, "Quantifying Reactor Safety Margins: Application of Code Scaling Applicability, and Uncertainty Evaluation Methodology to a Large-Break, Loss-of-Coolant Accident," issued December 1989). The staff found that the GEH QA procedure for a

code to attain Level 2 status is rigorous and meets the requirements of 10 CFR Part 50, Appendix B, Criterion III.

In RAI 21.6-92, the staff requested that GEH provide more detailed information on the exact code revision and version numbers used for all LOCA, stability, AOO, IE, and ATWS events. On July 31, 2008, and January 9, 2009, the staff received GEH's response to RAI 21.6-92 and the associated RAI 21.6-92 S01, respectively, which provided detailed tables with transient cases, code version used, QA level, hardware/operation system, and executable revision date. On March 16, 2009, GEH provided the staff with TRACG versions used for feedwater temperature operation domain and initial core topical report analysis. Based on the satisfactory response to the staff's request for exact code revisions, version numbers, and TRACG versions used in applicable LTRs, RAI 21.6-92 is resolved.

21.6.3 Staff Evaluation

The following sections document the basis for the staff's approval of the technical information submitted by GEH for the TRACG code in accordance with the guidance in SRP Section 15.0.2. GEH uses the TRACG coupled thermal-hydraulic and neutronic code to analyze the following DBAs:

- Large- and small-break LOCA and containment analyses
- Non-LOCA transients, including AOOs and IEs
- Stability analysis
- ATWS analysis

The references listed below fully document the staff's review of the LTRs for the above applications. The information is repeated and consolidated here for convenience to the reader. Some of the bases for the staff's acceptance of these licensing methodologies are proprietary and will not be discussed in detail in this document; however, the following references document these bases:

- NEDC-33083P-A, "TRACG Application for ESBWR," issued March 2005.
- Addendum with Open Items to the SER for NEDC-33083P-A, "Addendum to the Safety Evaluation Report with Open Items for NEDC-33083P-A, "Application of the TRACG Computer Code to the ECCS and Containment LOCA Analysis for the ESBWR Design,"" dated April 2, 2008.
- SER with open items for NEDC-33083P-A, Section 4, "Safety Evaluation Report with Open Items for the Application of the TRACG Computer Code to the Transient Analysis for the ESBWR Design," dated April 2, 2008,
- Addendum to the SER for NEDE-33083P-A, "Addendum to the Safety Evaluation Report for NEDC-33083P-A, "Application of the TRACG Computer Code to the ECCS and Containment LOCA Analysis for the ESBWR Design,"" dated September 20, 2010.
- SER for NEDE-33083P, Supplement 1, "Safety Evaluation by the Office of Nuclear Reactor Regulation Application of the TRACG Computer Code to Stability Analysis for the ESBWR Design NEDE-33083P, Supplement 1," dated August 29, 2007.

- Addendum with open items to the SER for NEDE-33083P, Supplement 1, “Addendum with Open Items to the Safety Evaluation by the Office of New Reactors Application of the TRACG Computer Code to Stability Analysis for the ESBWR Design NEDE-33083P, Supplement 1,” dated April 2, 2008.
- Addendum to the SER for NEDE-33083P, Supplement 1, “Addendum to the Safety Evaluation Report by the Office of New Reactors Application of the TRACG Computer Code to Thermal-Hydraulic Stability Analysis for the ESBWR Design NEDE-33083P, Supplement 1,” dated September 13, 2010.
- SER with open items for NEDE-33083P, Supplement 2, “Safety Evaluation with Open Items by the Office of New Reactors, Application of the TRACG Computer Code to Anticipated Transients Without Scram for the ESBWR Design NEDE-33083P, Supplement 2,” dated April 2, 2008,
- SER for NEDE-33083P, Supplement 2, “Safety Evaluation by the Office of New Reactors “TRACG Application for ESBWR Anticipated Transients Without Scram Analyses,” NEDE-33083P, Supplement 2, Revision 2,” dated October 20, 2010.
- SER for NEDE-33083P, Supplement 3, “Safety Evaluation for the TRACG Application for ESBWR Transient Analysis NEDE-33083P, Supplement 3, Revision 1,” dated September 14, 2010.

21.6.3.1 Documentation

The staff reviewed the documentation submitted by GEH. The staff determined that GEH included all of the documentation that describes (1) the evaluation model, (2) the accident scenario identification process, (3) the code assessment, (4) the uncertainty analysis, (5) a theory manual, (6) a user manual, and (7) the QA program.

The TRACG LTRs for LOCA (NEDC-33083P-A), AOO/IE (NEDE-33083P-A, Supplement 3), stability (NEDE-33083P-A, Supplement 1,), and ATWS (NEDE-33083P-A, Supplement 2) provide an overview of the respective evaluation models that describe all parts of the evaluation model, the relationships between them, and where they are located in the documentation. These LTRs also describe the accident scenario, including plant initial conditions, the initiating event, and phases of the accident.

The topical reports include documentation on the important physical phenomena, systems, and component interactions that influence the outcome of the accident. NEDC-33083P-A does not include any information about the RPV water level for the long-term core cooling phase of the LOCA. The staff received information on ESBWR long-term core cooling in letter MFN 05-105, from D.H. Hinds (GEH) to the NRC, “TRACG LOCA SER Confirmatory Items (TAC No. MC868), Enclosure 2, Reactor Pressure Vessel (RPV) Level Response for the Long Term PCCS Period, Phenomena Identification and Ranking Table, and Major Design Changes from Pre-Application Review Design to DCD Design,” dated October 6, 2005.

The topical reports also contain a determination of the code uncertainty for a sample plant calculation. In NEDC-33083P-A, GEH demonstrates the bounding LOCA calculation, instead of determining an uncertainty for this event. It is acceptable to use a bounding TRACG LOCA calculation for the ESBWR because the substantial margin prevents the ESBWR core from uncovering during a LOCA. Section 21.6.3.5.1 contains further discussion of this issue.

In NEDE-32177P (Revision 2), MFN 04-059, and NEDC-32725P (Revision 1), GEH provided the code assessment for TRACG. These documents include a description of each assessment test, the reason it was chosen, acceptance criteria, diagrams of the test facility that show the location of instrumentation that was used in the assessment, a code model nodalization diagram, and all code options used in the calculation. RAI 21.6-75 requested that GEH provide an update to the TRACG qualification report (NEDE-32177P, Revision 2) that is consistent with the current version of TRACG used in the ESBWR licensing analyses (TRACG04). In response, GEH submitted Revision 3 of the TRACG qualification report (NEDE-32177P) on August 29, 2007. In NEDE-32177P, Revision 3, qualification cases have been added in each of the major qualification categories. In the separate effects category, the additional cases (1) extend the range of the void fraction qualification to lower pressures and larger diameter geometries, (2) provide a qualification basis for TRACG prediction of core spray heat transfer, and (3) extend the fuel bundle pressure drop and critical power qualifications to include the current 10×10 fuel design. In the component category, a set of qualification cases has been added to evaluate the capability of the TRACG mechanistic core spray distribution model. In the integral systems category, qualification studies using data from the ROSA, FIX, and GIST test facilities have been added to provide additional support for TRACG LOCA applications. Finally, in the BWR plant category, qualification studies using stability data from Peach Bottom and Nine Mile Point have been added to support the application of TRACG for prediction of plant stability. The staff determined that the updated information is sufficient to extend the qualification to TRACG04. Therefore, based on the applicant's response, RAI 21.6-75 is resolved.

The staff determined that NEDE-32176P, Revision 4, is a self-contained document that describes the field equations, closure relationships, numerical solution techniques, and simplifications and approximations (including limitations) inherent in the field equations and numerical methods and limits of applicability for all models in the code.

The staff determined that the TRACG user manual (UM-0136, Revision 0) provides detailed instructions about how the computer code is used; a description of how to choose model input parameters and appropriate code options; guidance on code limitations and options that should be avoided for particular accidents, components, or reactor types; and, if multiple computer codes are used, documented procedures for ensuring complete and accurate transfer of information between different elements of the evaluation model. The LTRs (NEDC-33083P-A; NEDE-33083P-A, Supplement 1; NEDE-33083P-A, Supplement 2; and NEDE-33083P-A, Supplement 3) provide additional guidance on specific modeling of the events.

During three audits of GEH records, the staff reviewed the GEH documentation for the QA plan that describes the procedures and controls under which the code was developed and assessed, as well as the corrective action procedures that are followed when an error is discovered.

The staff requested that GEH update its documentation to reflect the current status of the code and current ESBWR plant design applicability. NEDC-33083P-A gives the application methodology and is based on the preapplication (4,000-MWt) design and TRACG nodalization. RAI 21.6-98 requests that GEH describe all design changes since the approval of TRACG for ESBWR LOCA analyses in NEDC-33083P-A and demonstrate that these changes would not alter the staff's conclusions. In the response to RAI 21.6-98 received on August 29, 2008, GEH provided the design changes and TRACG model justifications. In the response to RAI 21.6-98 S01, which the NRC received on March 3, 2009, GEH agreed to document the design changes and TRACG model justification in LTR NEDE-33440P, "ESBWR Safety Analysis—Additional Information," Revision 1 (issued June 2009). In the response, GEH listed all design changes

that have impacts on the LOCA analysis since the approval of TRACG for ESBWR LOCA analysis (NEDC-33083P-A) through ESBWR DCD Tier 2, Revision 5. With these new updates, the LOCA has been reanalyzed and documented in Sections 6.2 and 6.3 in the ESBWR DCD, Revision 6. Sections 6.2 and 6.3 of this report document the staff's evaluation of the LOCA analysis. The staff finds that Confirmatory Items 14 and 20, as mentioned in RAI 21.6-98, were addressed sufficiently. Based on the applicant's response, RAI 21.6-98 is resolved.

Because GEH provided some of the appropriate updates to the documentation in RAI responses, in RAI 21.6-63 S01, and in RAI 21.6-65 S02, the staff requested that GEH submit the updates in a single consolidated document. Specifically, the staff requested that GEH submit an update to the AOO portion of the TRACG topical report (Chapter 4 of NEDC-33083P-A) as either a stand-alone new topical report or a new supplement to NEDC-33083. On February 15, 2008, the staff received the response to RAI 21.6-63 S01, and RAI 21.6-65 S02, in which GEH stated that the requested information was consolidated in NEDE-33083, Supplement 3, "TRACG Application for ESBWR Transient Analysis", issued December 2007. A separate SER for NEDE-33083P, Supplement 3, provides the staff's technical evaluation of this LTR. Therefore, based on the applicant's response, RAIs 21.6-63 and 21.6-65 are resolved.

21.6.3.2 Evaluation Model

TRACG employs a two-fluid model for two-phase flow. It solves six conservation equations for both the liquid and gas phases, along with phasic constitutive relations for closure. In addition, a boron transport equation and a noncondensable gas mass equation are solved.

The spatially discretized equations are solved by donor-cell differencing in staggered meshes in one, two, or three dimensions. TRACG is used for both reactor vessel and containment. The list of constitutive models covers all important phenomena that may occur in a BWR, SBWR, or ESBWR.

21.6.3.2.1 Counter-Current Flow Condition

The action of steam flowing upward can impede the downward flow of cooling water and lead to the counter-current flow condition. GEH assessed the TRACG counter-current flow limitation (CCFL) model with data from the CSHT test facility. From the comparisons documented in NEDE-32177P, TRACG demonstrates that the code provides excellent agreement for saturated liquid. Agreement with subcooled liquid is excellent, with steamflow rates that are less than the condensation capacity. For flow rates greater than the condensation capacity, the average deviation between liquid downflow predicted by TRACG is within the measurement error. Therefore, the staff concludes that TRACG adequately predicts saturated CCFL and subcooled CCFL breakdown.

21.6.3.2.2 Heat Conduction

TRACG solves the heat conduction equation for the fuel rods (in cylindrical geometry) and for structural materials (in slab geometry) in the system. The latter has either a lumped slab model or a one-dimensional slab model. The strengths of the TRACG heat conduction model are the sophisticated transient gap conductance model and the implicit solution method that couples the heat transfer between the fuel rod and the coolant by iteration. The staff concludes that TRACG appropriately provides for the solution of heat conduction.

21.6.3.2.3 Wall Heat Transfer

TRACG has a very detailed wall heat transfer model based on the boiling curve. The model has standard heat transfer regimes—single-phase liquid or vapor, nucleate boiling, critical heat flux (CHF), transition boiling, film boiling, and condensation with and without the effect of noncondensables. There are correlations for transitions between different heat transfer regimes. The correlations for different regimes are standard correlations from the literature.

The code has been assessed with a variety of tests that have become the standards for assessing wall heat transfer. The assessments include thermal-hydraulic test facility (THTF) tests for film boiling heat transfer, CSHT tests that included thermal radiation heat transfer, and THTF tests for boiling transition, as well as critical power data gathered at the ATLAS facility. The staff concludes that the breadth and accuracy of the assessment cases demonstrate the acceptability of the TRACG capability to predict wall heat transfer.

21.6.3.2.4 Post-Critical Heat Flux Heat Transfer

TRACG has a rewet model for post-CHF heat transfer. With the exception of ATWS, none of the TRACG applications for the ESBWR experiences post-CHF heat transfer.

The staff reviewed the applicability of this model for ESBWR ATWS events as discussed in the “Safety Evaluation by the Office of New Reactors “TRACG Application for ESBWR Anticipated Transients Without Scram Analyses,” NEDE-33083P, Supplement 2, Revision 2.”

21.6.3.2.5 Flow Regime Maps

A two-fluid formulation relies on models for estimating interfacial transfer rates for mass, momentum, and energy. The models for interfacial processes, in turn, rely on the shape and size of the interface. Common practice is to develop flow regime maps to identify the distinct regime for two-phase distribution. The knowledge of the flow regime allows the code to select applicable correlations for transport processes.

The flow regime maps are generally two-dimensional maps between void fraction and mass flux. TRACG uses this approach to identify the two-phase flow regimes. It also has correlations for entrainment for dispersed flow regimes. Transition between annular flow and dispersed droplet flow is given by the onset of entrainment. For low vapor flow, annular flow will exist, and, as the vapor flux is increased, more and more entrainment will occur, causing a gradual transition to droplet flow.

The models for flow regime transitions in TRACG04 are qualified at low and high pressure. The staff reviewed the flow regime maps and transition between flow regimes and found them acceptable for the stated ESBWR applications. NEDC-33083P-A and the staff’s Addendum to the SER for NEDE-33083P-A document the details of the evaluation.

21.6.3.2.6 Interfacial Shear

The interfacial shear model was derived from the drift flux model using available experimental data at steady state. The models are based on current state-of-the-art technology and have been assessed with a large database covering the range of conditions expected in the reactor. The code uses a critical Weber number criterion for estimating interfacial area density or bubble/droplet diameter. However, the way this approach is used differs for interfacial

momentum and heat transfer in bubbly flow and droplet flow. NEDE-32176P, Revision 2, "TRACG Model Description," issued December 1999, provides an assessment of the interfacial shear through the capability of TRACG to predict void fraction data including single tube data, rod bundle data, and data for large hydraulic diameters. The test conditions used in the assessment cover both adiabatic tests, in which there is no effect of heat transfer on the void fraction, and heated tests. The tests cover a wide range of flow conditions, with varied pressure, flow rate, and inlet subcooling. Comparisons between TRACG and test data from sources such as the FRIGG and Christensen tests show calculations to be within the measurement error for the tests. The staff concludes that this demonstrates acceptable capability to predict interfacial shear.

The drift velocity used to calculate interfacial shear in the dispersed annular flow regime is based on the entrainment fraction. The staff requested in RAI 21.6-75 that GEH submit the updated qualification report (NEDE-32177P). In response, GEH submitted Revision 3 of the TRACG qualification report on August 29, 2007. Based on this submittal, RAI 21.6-75 is resolved.

The staff reviewed the GEH qualification of its void fraction data provided in this report to ensure that the modifications to the entrainment fraction and its subsequent use in the interfacial shear model compare well with data. The void fraction assessment results from NEDE-32177P, Revision 3, are very close to the results from NEDE-32177P, Revision 2, which was assessed as acceptable during the preapplication phase of the ESBWR design certification review. This ensures that the conclusion from the preapplication TRACG review is still valid. In addition, NEDE-32177P, Revision 3, adds assessment cases, which include Toshiba Low-Pressure Void Fraction Tests, Ontario Hydro Void Fraction Tests, and Centro Informazioni Studi Esperienze, SpA (CISE) Density Measurement Tests. The Toshiba tests were added to extend the qualification basis to lower pressures at 0.5 and 1.00 MPa (72.5 and 145 psi). The Ontario Hydro facility provides the void fraction database for a large-scale pumped flow facility. The CISE facility in Italy provided data concerning the void and quality relationship. The TRACG assessment showed reasonable agreement with the data from those tests. The assessment from NEDE-32177P, Revision 3, reinforced the conclusion from NEDC-33083P-A that the interfacial shear model is acceptable.

21.6.3.2.7 Wall Friction and Form Losses

The wall friction and form losses are important for predicting single- and two-phase flows. The code has standard models consisting of Moody curves for single-phase flow and a two-phase multiplier based on the Chisholm correlation.

Similarly, there is a standard model for form losses for abrupt area changes. The staff recognizes that simplifying assumptions are often necessary or expedient in computer code simulation of two-phase flow phenomena. However, the induced errors caused by simplifying assumptions should be understood. GEH determined those errors in the assumption of consistent wall friction and form loss partitioning between phases through code assessments using data from the FRIGG, Christensen, Wilson, and Bartolomei test programs (NEDE-32176P, Revision 2). In all assessment cases, the prediction-measurement standard deviation was shown to be on the order of the measurement error. In addition, wall friction assessments have been performed using data from the ATLAS facility over a range of flow conditions. The prediction-measurement comparisons show a calculated error rate on the order of the measurement error. The staff concludes that these assessments demonstrate acceptable capability to predict wall friction and form loss.

21.6.3.2.8 Critical Flow

Critical flow is calculated using coarse-mesh nodalization and semi-empirical approximation for choking criteria. The critical flow model also allows for choking in the presence of noncondensable gases. The critical flow model in TRACG has been assessed against data from the Marviken critical flow tests, pressure suppression test facility (PSTF), and Edwards test. The Edwards and PSTF tests are small scale, and the Marviken tests are large scale. In each blowdown period, the measured and predicted mass flows were in good agreement with the predicted bounding. The timing of the transition was also in good agreement. The predicted mass flow rates were generally conservative compared with the data in the smaller scale tests. Comparison of TRACG predictions versus data from tests in different scale test facilities show that TRACG generally overpredicts the data and is therefore conservative. The critical flow model is detailed, well defined, and acceptable for predicting choked flow.

In an RAI (6.3-13) related to the choked flow model used in ESBWR LOCA analyses, the staff asked GEH to include the RPV injection line nozzle and equalizing line nozzle throat length to diameter (L/D) ratios in ITAAC to ensure that the L/D ratio remains within the applicability range of the TRACG code flow choking model for LOCA calculations. In NEDE-32176P, Revision 3, Section 6.3 describes the TRACG04 choked flow model, and Section 6.3.3 describes the calculation of the sonic velocity. In Section 6.3.3, GEH stated the simplifying assumptions used to calculate the sonic velocity, which include assuming equilibrium conditions. GEH stated, "Under certain circumstances, the equilibrium assumption may break down. In particular, for break assemblies of very short length, non-equilibrium transport behavior may be important." In a supplemental RAI, the staff asked that GEH address questions related to the applicability of the TRACG04 flow choking model to the ESBWR RPV injection line and equalizing line nozzles. By letter dated March 5, 2008, the applicant submitted its response to RAI 6.3-13 S01. The response included the following information:

- TRACG has a subcooled choking model applicable for small L/D throat conditions. The model prediction comparisons to data include choked flow for both smooth and abrupt area changes (i.e., orifices), thus validating the model for small L/D conditions.
- TRACG is qualified over a range of L/D of 0.0–8.68 through direct comparison to test data. GEH provided a table of tests, which contains the L/D for the PSTF critical flow tests, Marviken, and the Edwards Pipe Tests used to qualify the TRACG critical flow model.
- GEH provided a table of L/Ds for ESBWR break lines. The values of L/Ds of ESBWR break lines are within the ranges of the TRACG qualification database.

Recognizing that it is not possible to have continuous L/D values in the range of test data, the ESBWR break throat L/D values are within the range of tests used to qualify the TRACG code choking model. Based on the RAI response, the staff concluded that the TRACG model covers L/Ds for the ESBWR break lines. The staff reiterated the original request for an ITAAC on throat L/Ds in RAI 6.3-13 S02. In response, GEH added ITAAC 13 and 14 to the GDACS Table 2.4.2-3 of DCD, Tier 1, Revision 9. Therefore, based on the applicant's response, RAI 6.3-13 is resolved.

21.6.3.2.9 Two-Phase Level Tracking

A two-phase level may exist in the bypass, lower plenum, downcomer, chimney, drywell, and wetwell. The two-phase level-tracking model invokes some approximations for the void fraction

above and below the mixture level that may not be accurate if significant voiding occurs below the mixture level. The model has been assessed with PSTF level swell tests. Comparisons of the predicted versus measured level indicate that TRACG was generally able to predict the measured level to an accuracy consistent with the measurement uncertainty. Sensitivity studies were also performed on nodalization, convergence ratio, and time step size. Little sensitivity was found in the studies. The staff concludes that TRACG adequately models level swell as evidenced by code predictions that fall within the experimental measurement uncertainty.

21.6.3.2.10 Flashing

Vapor generation or flashing is an important phenomenon for any depressurization transient such as a LOCA. The vapor generation is predicted by energy balance at the interface, where the differences in heat fluxes result in phase change. TRACG has a mechanistic model for interfacial heat transfer that depends on interfacial area and the shape of the interface. The interface is defined on the basis of flow regime. The model has been assessed with a variety of tests. TRACG predictions were reasonable, indicating that the models are applicable to LOCAs. The staff notes that there are limits on bubble size and number density in bubbly and droplet flow regimes.

In addition, as is the case with all thermal-hydraulic system codes today, there is an inconsistency in the interfacial area used for momentum transfer and heat transfer in bubbly and droplet flows. However, the staff finds that the good agreement with the void fraction and heat transfer data shows that these limits do not adversely affect the results.

21.6.3.2.11 Minimum Stable Film Boiling Temperature

For the minimum stable film boiling temperature, GEH used the Iloeje correlation for ESBWR applications. GEH added the option of using the Shumway correlation to calculate the minimum stable film boiling temperature in TRACG, and GEH stated that the flow and pressure dependence are captured better for the Shumway correlation. The staff has not reviewed the Shumway correlation and supports the continued use of the Iloeje correlation for ESBWR applications for LOCA, AOO, and ATWS. For LOCA and AOO events for the ESBWR, the core does not enter film boiling, and therefore this correlation is not used. For ESBWR ATWS events in which the core does go into film boiling, the minimum stable film boiling temperature is used only to determine when the core will quench. In RAI 21.6-79 S01, the staff asked GEH to justify the high ranking of this parameter for the TRACG application for BWR/2–6 AOOs (NEDE-32906P, Revision 2, “TRACG Application for Anticipated Operational Occurrences (AOO) Transient Analysis,” dated February 28, 2006.) The GEH response to RAI 21.6-79 S01 explained that PIRT C13 pertains to both dryout and rewet/boiling transition. C13 is ranked as a high PIRT parameter for both ESBWR and BWR/2–6 AOO events because of the importance of calculating a margin to dryout. However, no ESBWR or BWR/2–6 AOO events exceed the minimum critical power ratio (MCPR) where minimum stable film boiling temperature may be encountered. Therefore, the rewet portion of C13 is not of high importance. The staff accepts GEH’s explanation as to why C13 is ranked as a high PIRT parameter for both ESBWR and BWR/2–6 AOO events. Based on the applicant’s response, RAI 21.6-79 is resolved.

21.6.3.2.12 Critical Heat Flux

For CHF, TRACG has a proprietary correlation, the GEH critical quality boiling length correlation (GEXL), which is based on the critical quality concept for normal flows and uses a modified Zuber correlation for low flows and flow reversal. Section 4.4 of this report discusses the

applicability of the GEXL correlation for the ESBWR and the RAs associated with this topic and finds the use of the GEXL correlation for the ESBWR to be acceptable.

21.6.3.2.13 Gap Conductance

TRACG has the option of using either a constant or dynamic gap conductance. The dynamic gap conductance is used in the ESBWR for AOO/IE, stability, and ATWS events. For LOCA events, GEH chose the constant gap conductance option. These gap conductance values are generated using the GESTR thermal mechanical code.

The dynamic gap conductance is modeled as the sum of the contributions from radiation heat transfer, thermal conduction through the gas mixture in the asymmetric radial gap, and conduction through the fuel/cladding contact spots. The conductance of the gas in the radial gap depends on the effective gap size and accounts for the asymmetric radial displacement of cracked pellet wedges. The contact conductance depends on the size of the gap after accounting for fuel and cladding thermal expansion.

The radiation heat transfer between the fuel pellet and cladding is modeled by a conventional radiation heat transfer coefficient with separate thermal emissivities for the pellet and clad surface.

The conductance across the gas gap is calculated as the gas gap thermal conductivity divided by an effective gap modified for temperature jump at the gas-solid interface and the effect of a discontinuous gas gap resulting from contact spots. The gas in the gap is composed of helium and fission gas. An effective thermal conductivity is calculated for the gap gas. The helium pressure, composition of the fission gas, and relative amount of xenon and krypton in the fission gas are all obtained from the GESTR fuel files.

The internal gas pressure is calculated by considering gas in the volume along the length of the fuel column and the gas in the fuel rod plenum. Outputs from GESTR-LOCA are used to calculate the initial fuel column volume-to-temperature ratio. The staff concluded in NEDC-33083P-A that this use of the NRC-approved GESTR-LOCA method to set initial steady-state conditions is acceptable. In addition, the resulting cladding hoop stress is conservatively predicted.

The cladding average temperature at the maximum linear heat generation rate axial position is used in calculating the growth in the volume of the fuel gas plenum in a transient from thermal expansion. The plenum gas temperature is calculated separately from the gas temperature in the gap of the fuel column.

TRACG has models for gap conductance after cladding perforation. The gas conductivity is adjusted to reflect the presence of a stoichiometric mixture of steam and hydrogen from the metal-water reaction. The constants in the equation for the gas conductivity in a perforated fuel rod are TRACG input constants. The ESBWR is not expected to experience rod perforation during any LOCA, stability, AOO/IE, or ATWS event. NEDC-33083P-A documents this model. The TRACG gap perforation model is comparable to the model in SAFER, a code previously reviewed and approved by the NRC. The cladding rupture stress and plastic strain are based on experimental data that the staff has reviewed and approved.

GEH demonstrated that the calculated transient gap responses are in good agreement with those calculated by SAFER/GESTR. The staff's SER included in NEDC-33083P-A documents additional details of the staff's review of the TRACG gap conductance model.

21.6.3.2.14 Fuel Rod Thermal Conductivity

The default fuel thermal conductivity modeling in TRACG04 is based on the PRIME03 code, which the NRC has not reviewed and approved for the ESBWR. RAI 6.3-54 requested that GEH justify use of the PRIME03-based thermal conductivity model in TRACG04, since PRIME03 has not been reviewed and approved by the NRC for the ESBWR. RAI 6.3-55 requested that GEH justify the use of gap conductance and fuel thermal conductivity from different models (GSTRM and PRIME03-based TRACG04, respectively).

GEH's response to RAI 6.3-55 included a description of the TRACG04 calculations, as discussed in the following paragraphs concerning RAI 6.3-54. The response to RAI 6.3-55 did not provide sufficient justification for combining models. However, the response to RAI 6.3-54 S01, addressed the impact of using gap conductance and fuel thermal conductivity from different models (GSTRM and PRIME03-based TRACG04, respectively) on TRACG04 calculations. Since the supplements to RAI 6.3-54 addressed the issue, the staff concluded that RAI 6.3-55 is resolved.

The GEH response to RAI 6.3-54 states that the fuel files generated using the GSTRM code are being used as input to TRACG04 and that the TRACG04 thermal conductivity model is used. The TRACG04 thermal conductivity model is based on the thermal conductivity model in the PRIME03 code and accounts for the degradation of thermal conductivity due to the presence of gadolinium and for the degradation of thermal conductivity as exposure increases. Since the TRACG04 thermal conductivity model has not been approved in previous versions of TRACG and since the thermal conductivity model has not been approved as part of a PRIME03 review for the ESBWR, in RAI 6.3-54 S01, the staff requested that GEH provide experimental data and benchmarks, as well as study results comparing TRACG02 (GSTRM) to TRACG04 (PRIME03-based) thermal conductivity sensitivity. In responding to RAI 6.3-54 S01, GEH provided the results from sensitivity studies comparing representative AOO, ATWS, and stability cases analyzed with the GSTRM model and the TRACG04 (PRIME03-based) model to the base cases using GSTRM gap conductance and TRACG04 (PRIME03-based) thermal conductivity. GEH did not submit experimental data and benchmarks to support use of the PRIME03 code or the TRACG04 thermal conductivity model for the ESBWR.

For AOOs, the generator load rejection with total bypass failure (LRNBP) from ESBWR DCD Tier 2, Section 15.3.5 was selected as the transient event (AOO/IE) for the sensitivity study. This transient event is expected to be the one most affected by the fuel thermal conductivity and gap conductance because it is a fast event with the most severe flux peak. The LRNBP sensitivity study results in the response to RAI 6.3-54 S01 (Table 6.3-54-1), show negligible differences ($< 1\% \Delta P$ and $< 0.005 \Delta CPR/ICPR$) in maximum dome pressure, maximum vessel bottom pressure, and $\Delta CPR/ICPR$; (CPR is the critical power ratio). In addition, RAI 6.3-54 S02, requested that GEH provide the fuel centerline temperatures and melting temperatures for the LRNBP cases.

The results transmitted in the response to RAI 6.3-54 S02 show that the base LRNBP case (GSTRM gap conductance and PRIME03-based thermal conductivity) yields the most conservative maximum fuel centerline temperature. The response to RAI 6.3-54 S02, also

shows that the uranium dioxide melting temperatures for all three cases are identical, since melting temperature is a function of exposure, and all of the cases assume the same exposure.

The main steam isolation valve (MSIV) closure from ESBWR DCD Tier 2, Section 15.5.2 was selected as the ATWS event analyzed in the sensitivity study. This ATWS event is expected to be the one most affected by the fuel thermal conductivity and gap conductance. The MSIV closure sensitivity study results shown in the response to RAI 6.3-54 S01 (Table 6.3-54-2), show negligible differences in associated containment pressure (approximately 1 percent ΔP), maximum bulk SP temperature (< 1.1 degrees Celsius [C] [2 degrees Fahrenheit [F]]), and peak cladding temperature (less than 5.6 degrees C [10 degrees F]).

The AOO and ATWS sensitivity study results documented in the response to RAI 6.3-54 S01, provide the staff with reasonable assurance that the transient event analyses shown in the ESBWR DCD and in the TRACG analyses for ESBWR AOO and ATWS topical reports do not exceed acceptance criteria. Based on the applicant's response, RAI 6.3-54 is resolved.

The staff accepts the use of the GSTRM model for both gap conductance and thermal conductivity in the ESBWR design certification. The conclusions and limitations for ESBWR TRACG AOO and ATWS analyses (including the 2.41-MPa [350-psi] critical pressure penalty) contained in the staff's evaluation of GEH's Part 21 report (Appendix F to the safety evaluation for NEDC-33173P) are applicable to this safety evaluation. The NRC must approve the use of other methods or analysis strategies for the ESBWR.

The loss of feedwater heating (LOFWH) regional stability evaluation at middle-of-cycle exposure from ESBWR DCD Tier 2, Section 4D.1.5 was chosen for the stability sensitivity study because it is the limiting stability event. A comparison of the decay ratio results from the base case and two sensitivity cases shows a negligible change in decay ratio between the base case (with GSTRM gap conductance and PRIME03-based thermal conductivity) and the PRIME03-based sensitivity case. However, the GSTRM sensitivity case resulted in a relatively limiting decay ratio (0.71 for the GSTRM case versus 0.66 for base case and PRIME03-based case).

The results of the LOFWH regional stability sensitivity studies give the staff reasonable assurance that the ESBWR TRACG 0.8 decay ratio limit is not exceeded by the stability results shown in the ESBWR DCD and in TRACG for the ESBWR stability topical report. In addition, the stability analysis will be analyzed on a cycle-specific basis, so these results will be updated.

The staff accepts the use of the GSTRM model for both gap conductance and thermal conductivity in the ESBWR design certification. The conclusions and limitations for ESBWR stability analyses (including the 2.41-MPa [350-psi] critical pressure penalty) contained in the staff's evaluation of GEH's Part 21 report (Appendix F to the safety evaluation for NEDC-33173P) apply to this safety evaluation. The NRC must approve the use of other methods or analysis strategies for the ESBWR.

GEH did not include LOCA sensitivity studies in response to RAI 6.3-54 S01, because the water level remains above the top of active fuel in ESBWR LOCA analyses. Consequently, there is no fuel heatup. The impact of fuel thermal conductivity and gap conductance is much less significant than in cases where fuel heatup is calculated. In addition, dynamic gap conductance is not used in LOCA analysis because the PIRT parameters related to gap conductance were not determined to be of high importance to ESBWR LOCA analysis (NEDC-33083P). The staff performed confirmatory calculations of ESBWR LOCA fuel conductivity sensitivity using the TRACE model. The results showed that the minimum water level in the limiting LOCA is not

sensitive to the 30-percent fuel thermal conductivity reduction. (The 30-percent fuel thermal conductivity impact was a bounding reduction used by the staff in its confirmatory calculations to verify the GEH calculation results showing that AOO and IE results are not sensitive to the PRIME and GESTR fuel thermal conductivity model differences.)

Therefore, the staff has reasonable assurance that the LOCA acceptance criteria are not exceeded in the LOCA analyses in the ESBWR DCD and in the TRACG for ESBWR LOCA analysis topical report.

The staff accepts the use of the GSTRM model for both gap conductance and thermal conductivity in the ESBWR design certification. The conclusions and limitations for ESBWR TRACG LOCA analyses (including the 2.41-MPa [350-psi] critical pressure penalty) contained in the staff's evaluation of GEH's Part 21 report (Appendix F to the safety evaluation for NEDC-33173P) are applicable to this safety evaluation. The NRC must approve the use of other methods or analysis strategies for the ESBWR.

21.6.3.2.15 Neutron Kinetics Model

TRACG can perform three-dimensional neutron kinetics calculations. To perform these calculations, TRACG uses input from the PANAC11/TGBLA06 codes. The staff reviewed the PANAC11 and TGBLA06 methods in detail. Section 4.3.3 of this report discusses the staff's review. This section briefly discusses TRACG-specific models and the interface between TRACG and PANAC11/TGBLA.

TRACG04 has a one group, coarse-mesh, nodal diffusion model with six delayed neutron precursor groups. The nodal flux calculation is the same as that performed in the PANAC11 BWR core simulator. The transient flux solution is obtained by integrating the differential neutron precursor and flux equations over space and time and solving the equations by employing a discontinuous flux and continuous current approximation. TRACG also uses cross sections generated by PANAC11/TGBLA06 as input by means of a PANAC11 "wrapup" file. GEH submitted the contents of the wrapup file, which the staff reviewed to determine that the information transmitted to TRACG adequately represents the nuclear cross sections. The staff also reviewed and found acceptable the initialization of the TRACG steady-state power distribution to that from PANAC11, given that the two codes have different thermal-hydraulic models. The staff's "Safety Evaluation Report by the Office of Nuclear Reactor Regulation Application for GE14 for ESBWR Nuclear Design Report (NEDC-33239P) and Gamma Thermometer System for LPRM Calibration and Power Shape Monitoring (NEDE-33197P) LTRs for Reference in the ESBWR Design Certification Application (TAC No. MD1464)" includes the staff's review of these processes.

The PANAC11 void fraction model is based on the Findlay-Dix correlation. The staff has questions regarding the applicability of this correlation to the ESBWR. In RAI 4.4-2 and the associated supplements, the staff requested additional information on the uncertainty and applicability associated with the correlation and how it is incorporated into the Δ CPR calculation performed using TRACG and ultimately the operating limit maximum CPR limit. The staff's safety evaluation in Section 4.4 of this report discusses the resolution of RAI 4.4-2 and the associated supplements.

The important neutronics parameters for ESBWR AOOs are void coefficient reactivity feedback, Doppler reactivity feedback, scram reactivity, and three-dimensional kinetics.

21.6.3.2.15.1 *Void Coefficient*

The void coefficient determines the power spike given a void collapse that results from a pressurization event or cold water event.

The void coefficient is implied in how the TRACG neutronics parameters (i.e., infinite multiplication factor, migration area, fast group removal cross section, and fast group diffusion coefficient) change as the local void fraction or moderator density changes. The dominant neutronics parameter for changes in void coefficient is the infinite multiplication factor. The uncertainty and biases for the infinite multiplication factor, which is a function of history-weighted moderator density and exposure, is determined by comparing TGBLA06 (the GEH lattice physics code) and MCNP.

In RAI 21.6-84, the staff requested that GEH provide the documentation of the evaluation of the TGBLA06 lattice calculations relative to MCNP in order to reestablish the void coefficient correction model as applied to TRACG.

The GEH response to RAI 21.6-84 notes that the void coefficient reassessment was completed for TRACG04 in topical report NEDE-32906P, Supplement 3, issued May 2006. This reassessment for TGBLA06 against MCNP results occurred, and the void coefficient correlation model to be applied for TRACG04 was updated prior to performing the TRACG04 qualification cases that required the use of the three-dimensional neutron kinetics model. A detailed discussion of this item appears in Section 3.20.2 of the staff's "Final Safety Evaluation of GEH's LTR NEDE-32906P, Supplement 3, 'Migration of TRACG04/PANAC11 from TRACG02/PANAC10 for TRACG AOO and ATWS Overpressure Transients,'" dated July 10, 2009. Based on the applicant's response, RAI 21.6-84 is resolved.

21.6.3.2.15.2 *Doppler Coefficient*

The Doppler coefficient is a function of exposure and moderator density and has an uncertainty of 4 percent (NEDC-33083P-A). The Doppler coefficient simulates the resonance absorption in uranium and plutonium and the broadening of the resonance absorption as the fuel temperature increases. Therefore, it is negative. In response to RAI 21.6-60, GEH provided the results of sensitivity studies that were performed by perturbing the Doppler uncertainty and showed that there was little sensitivity to $\Delta\text{CPR}/\text{ICPR}$ for the LOFWH and the generator load rejection with a single failure in the turbine bypass system. GEH also showed that there was little sensitivity to the peak pressure to the MSIV closure event. In addition, although GEH ranks this parameter as having "medium" importance, it still includes the uncertainty in the uncertainty analysis for the ESBWR AOO and IE. The staff recognizes that the uncertainty for the Doppler coefficient was determined based on PANAC10. Based on the applicant's response RAI 21.6-60 is resolved.

During the review of TRACG04 as applied to the operating fleet (NEDE-32906P, Supplement 3, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10 for TRACG AOO and ATWS Overpressure Transients," issued May 2006), the staff requested that GEH justify that the uncertainty is applicable or bounding for PANAC11. RAI 21.6-108, in regard to NEDC-33083P-A, also addressed this question. In that RAI, the staff requested that GEH demonstrate that PIRT items C1BX and C1CX (uncertainty in the Doppler coefficient and in scram reactivity, respectively) in Table 4.4-1 of NEDC-33083P-A are still applicable or bounding when applying the PANAC11 physics methods.

GEH responded to RAI 21.6-108, which stated that GEH had previously addressed this issue in its response to NEDC-32906P, RAI 21. That response is summarized as follows:

- The scram reactivity uncertainty (C1CX) is dominated by the uncertainty in determining the scram speed. The scram speed uncertainty is determined based on plant data obtained from scram speed tests at BWR plants and does not depend on the lattice or core physics methods.
- The Doppler coefficient uncertainty (C1BX) is conservatively determined based on calculated responses for the SPERT tests. C1BX was not directly established from lattice physics calculations. Therefore, this parameter does not directly depend on the lattice physics methods.

The GEH response to RAI 21 contains GEH analysis results that show the continued applicability of the Doppler coefficient uncertainty to the TRACG04 AOO calculations.

Based on the GEH responses, RAI 21.6-108 is closed.

21.6.3.2.15.3 *Scram Reactivity*

TRACG simulates the scram reactivity by changing the neutronics parameters from uncontrolled to controlled as the control rods move into the core. The timing of the control rod movement is determined by user input and by trips relative to specified control points in the TRACG model (e.g., turbine control valve closing, MSIV closing). The worth associated with the control movement is determined by how the neutronics parameters change from uncontrolled to controlled (i.e., control rod is present or not present in the core bypass next to the fuel assemblies simulated).

The staff requested that GEH justify the uncertainty values chosen for the scram reactivity as part of the review for migration to TRACG04/PANAC11 for BWR/2–6 AOOs (NEDE-32906P, Supplement 3). These uncertainties, established using the PANAC10 model, are also being used for the TRACG04/PANAC11 application for the ESBWR AOO and IE.

RAI 21.6-108 addressed this question with regard to NEDC-33083P-A. In RAI 21.6-108, the staff requested that GEH demonstrate that PIRT items C1BX and C1CX (uncertainty in the Doppler coefficient and in scram reactivity, respectively) found in Table 4.4-1 of NEDC-33083P-A are still applicable or bounding when applying the PANAC11 physics methods. As discussed in Section 21.6.3.2.15.2 of this report, and based on the applicant's response, RAI 21.6-108 is resolved.

21.6.3.2.15.4 *Boron Reactivity*

TRACG04 models the negative reactivity from boron by adjusting the absorption cross section for other preexisting neutron removal mechanisms already modeled in TRACG.

The staff believes that GEH accounts for all of the factors affecting boron reactivity in the development and testing of its empirical model. However, the only GEH validation for TGBLA available for staff review is a code-to-code comparison to PANAC11.

The staff performed independent MCNP calculations to compare the efficacy of the empirical cross-section model to account for the spectral shift consistent with MCNP calculations

performed for different fuel lattices at a variety of exposure histories to examine the impact of exposure effects on the instantaneous nodal thermal spectrum. The staff calculations confirm the validity of the TRACG boron reactivity model.

21.6.3.2.15.5 *Xenon*

TRACG accounts for the negative reactivity from xenon by adjusting the thermal removal cross section at each node. The PANAC11 wrapup file includes the xenon number density and the microscopic absorption cross section. In RAI 21.6-82, the staff requested that GEH provide information on whether transient xenon conditions were modeled in the AOO or ATWS analyses. In response to RAI 21.6-82, GEH stated that the xenon concentration is not updated during a transient. The staff finds this acceptable for simulating stability, AOO, IE, and ATWS events because the time scales for these events are not long enough for the xenon concentration to change appreciably. However, the staff questioned the startup evolution, which will take place over the course of hours. In RAI 21.6-82 S01, the staff requested that GEH justify use of the constant xenon assumption for the startup simulation. GEH responded to RAI 21.6-82 S01 and also the responses to RAIs 4.4-59 and 4.4-60 provide additional information on the xenon assumption for startup. The detailed discussion of the staff's evaluation of this issue appears in the Addendum to the SER for NEDC-33083P, Supplement 1, Section 6.0. GEH provided sufficient information on the xenon assumption for startup. Therefore, based on the applicant's responses, RAIs 21.6-82, 4.4-59, and 4.4-60 are resolved.

21.6.3.2.15.6 *Decay Heat Modeling*

LOCA

During an audit of TRACG as applied to the ESBWR LOCA, the staff reviewed several documents detailing the procedures and calculations performed to determine the shutdown power curve presented in ESBWR DCD Tier 2, Figure 6.3-39. The shutdown power is a combination of several heat sources and contributes to the integrated thermal load to be absorbed by the containment. It is also a factor in the determination of margin to specified acceptable fuel design limits during DBAs.

For the ESBWR, the shutdown power is calculated using an offline code and incorporated into TRACG analyses by means of a normalized power table. The TRACG calculation employs the predetermined normalized power table based on a reactor trip signal.

The shutdown power following a scram signal during a design-basis LOCA includes many heat sources, such as those listed below:

- Transient fission power during the signal processing and logic delay
- Transient fission power during hydraulic control unit valve deenergization and stroke
- Transient fission power during control blade insertion
- Power from delayed neutron-induced fission
- Decay of radioactive fission products
- Decay of activated fission products
- Decay of actinides in the fuel
- Stored energy in the fuel, cladding, vessel, and vessel internals
- Decay of activated nuclides in the cladding and other structural materials
- Exothermic energy release from water-zirconium reactions

The staff reviewed the specific means employed by GEH for calculating each of these contributions to the total shutdown power. Earlier DCD revisions contained an inconsistent description of the decay heat standard used in the TRACG model, and in RAI 6.3-80, the staff requested clarification. In response, GEH clarified a typographical error and stated that the decay heat curve was based on the American National Standards Institute/American Nuclear Society (ANSI/ANS) Standard 5.1-1994, "Decay Heat Power in Light Water Reactors," and that there are no differences between the method reviewed in the TRACG audit and the decay heat curve used for ECCS performance analysis in the DCD. Based on the applicant's response, RAI 6.3-80 is resolved.

In RAI 6.3-62, the staff requested additional decay heat modeling details. In response, the applicant detailed the power used in the LOCA analysis. The ESBWR decay heat was generated based on ANSI/ANS Standard 5.1-1994 with additional terms for a more complete shutdown power assessment. The heat sources in the model include decay heat from fission products, actinides and activation products, as well as fission power from delayed and prompt neutrons immediately after shutdown. The effect of neutron capture in fission products is considered. GEH assumed an end-of-cycle exposure of 32 GWD/short ton and an irradiation time of 3.8 years for decay heat calculation. Irradiation time is the most sensitive input in the decay heat model. Increasing irradiation time results in increased contributions from the long-lived actinides, which thus results in higher shutdown powers. The irradiation time of 3.8 years is approximately 8-percent higher than the average batch in the equilibrium cycle. Therefore, the staff considers the assumption used for the decay curve to be conservative.

In addition, GEH provided assumptions related to scram delay times, which included instrument detection of the plant parameters and delay from signal processing. In RAI 6.3-62, the staff also asked GEH to justify the use of the same decay heat curve for both small- and large-break LOCAs. GEH provided a power comparison between the MSIV closure transient at end of cycle and a decay curve used in the LOCA analysis. In the MSIV closure transient, a power increase is experienced at the beginning due to negative void feedback compared to power response in a small-break LOCA. The comparison showed that the decay heat curve bounds the MSIV transient power curve, which implies that the decay curve will bound the small-break LOCA as well and that the decay curve used is conservative. However, from the RAI discussion, the staff noted that the assumptions for the scram signal delay time are different in the MSIV closure transient than in the LOCA event. By estimating additional energy for the small-break LOCA and considering the scram delay time, the additional energy could boil off an additional volume of water in the vessel. The staff estimated this additional volume of water by subtracting this amount of water from GEH's minimum level prediction and then estimated a new minimum water level. The estimated minimum water level is still above the top of the active core. Considering that the decay power calculation includes other conservative assumptions, the staff accepts GEH's approach of using a single decay curve for all LOCA analyses. Based on the applicant's response, RAI 6.3-62 is resolved.

AOO/IE

For AOO/IE events, TRACG directly calculates the decay heat. The TRACG decay heat model calculates the delayed component of the volumetric heat generation rate in the fuel. The initial nodal decay heat is assumed to be proportional to the fission density in each node. In the transient analysis, TRACG calculates the total nodal power according to the transient flux solution for the fraction of the power produced from fission. This contribution is combined with the decay power predicted using the ANS standard. The total is the transient nodal power. Section 9.3.1 of NEDE-32176P, Revision 3, "TRACG Model Description," issued April 2006,

describes this process. The values for the decay heat fractions and the time constants used to calculate the decay heat component are determined from the default May-Witt decay power curves and the 1979 or 1994 ANS standard decay heat models. The user may also specify decay heat group constants through input. For the ESBWR, the 1979 ANS standard is used for transient calculations.

The ANS standards model the total decay heat as the sum of the contributions from fission products, major actinides, miscellaneous actinides, structural activation products, and fission power. The decay heat model does not explicitly account for stored energy since heat structures in TRACG account for this.

The staff finds that GEH has adequately accounted for all major contributors to the decay heat model and that the decay heat model is adequate for simulation of AOO and IE events in the ESBWR. All transients that are to be analyzed with the application methodology in Section 4 of NEDE-32176P, Revision 3, experience the limiting conditions before the scram such that the decay heat curve is not as important. The addition of power from decaying isotopes during normal operations is typically on the order of 5 to 6 percent, and an uncertainty of this small a contribution has little or no effect on the overall transient response.

21.6.3.2.16 Numerics

TRACG numerics are a significant improvement over those of its predecessor, TRAC-BD1/MOD1. As a default, TRACG employs fully implicit integration for hydraulic equations. The fully implicit integration is accomplished by means of a predictor-corrector iterative technique.

TRACG solves the heat conduction equations by implicit integration. The heat transfer coupling between the heat conduction and coolant hydraulics is also treated implicitly via an iterative technique. This implicit coupling represents a significant improvement over commonly used explicit coupling, which may incur an error on the phase shift and amplitude in a thermally-induced oscillation.

For the channel components in the time-domain stability analyses, TRACG uses an optional explicit integration because the implicit integration may suppress real physical oscillations. Artificial numerical damping may arise from finite spatial and temporal differencing. This damping is minimized by using an explicit first-order finite differencing method and maintaining the Courant number near 1. The staff found the explicit integration scheme in TRACG an acceptable part of the methodology used for calculating stability margins in ESBWR.

The adequacy of the TRACG field equations and the solution methods have been assessed in NEDC-33083P-A. However, the staff recently identified an error in the TRACE code momentum equation, which overpredicts pressure drops. The staff further concluded that the error was in the original TRAC-P and TRAC-B, which were the basis of the TRACE and TRACG codes, respectively.

In RAI 21.6-123, the staff requested that GEH determine the magnitude of the error in the TRACG momentum conservation equations for the flow from the downcomer through lower plenum to core inlet for the ESBWR configuration. In addition, the staff asked GEH to provide an assessment of the impact of the error in momentum formulation for the analysis supporting the ESBWR DCD and topical reports. In response to RAI 21.6-123, GEH provided analysis of the ESBWR inlet plenum configuration and the effect that the identified three-dimensional momentum equation error may have on ESBWR safety analysis. GEH concluded the following:

TRACG models have a deficiency. When calculating 3D flow (e.g. in the lower plenum region), TRACG over-estimates the pressure drop when there are 90 degree flow turns. By analysis, GEH has concluded that the magnitude of this over-prediction is proportional to the density times the velocity squared; thus at low velocities, the over-prediction is small. GEH has quantified an upper estimate of this error in the lower plenum (single phase) pressure drop for ESBWR conditions.

The staff performed a series of simple LAPUR steady-state calculations to quantify the effect of this additional and non-physical TRACG pressure drop on the ESBWR core flow. The staff estimates that the ESBWR flow should be approximately 1.5-percent higher than the flow calculated by TRACG (if the additional non-physical pressure drop is removed). Therefore, for most events, the error adds conservatism.

In response to RAI 21.6-123, GEH evaluated the impact on ESBWR accidents and concluded that there is no significant impact in the safety analysis due to lower flow in the ESBWR as detailed below:

- AOOs: GEH performed a core flow reduction sensitivity analysis using TRACG and observed no significant effect on any AOO. The flow reduction used by GEH bounds the staff's estimation of 1.5-percent flow reduction related to the three-dimensional momentum equation error. The staff accepts that the momentum equation error has a negligible impact on AOOs.
- ATWS: GEH quoted an analysis stating that the core flow reduction due to channel spacer loss increases with a much larger scale compared to the flow reduction due to the momentum error and has only a minimal effect on ATWS performance. Therefore, the core flow reduction caused by the lower plenum differential pressure overprediction is expected to have a minimal effect on ATWS performance. The primary reason for this result is that the ESBWR has significant margin for all three ATWS acceptance criteria: peak cladding temperature (PCT), vessel overpressure, and containment integrity. Since significant margin is available, the staff concurs that flow reduction attributable to the momentum error has no significant impact.
- LOCA: The lower plenum DP error will have no significant impact on the RPV level and the long-term containment pressure in the LOCA analyses. For the LOCA events, GEH argued that the power output drops very quickly after the reactor scram. The natural circulation flow through the downcomer and core reduces correspondingly.
- In the TRACE momentum equation qualification study, the staff corrected the momentum equation error and confirmed that the impact on the RPV level is negligible in LOCAs. Therefore, the staff agrees that the impact on LOCA analysis is small.
- Stability: GEH argued that the RPV lower plenum pressure drop overprediction would lower the core flow, which would be a conservative assumption for stability because lower core flow causes a higher power/flow ratio and leads to a higher decay ratio. This error may have a significant nonconservative effect on the stability of the core-wide stability mode. The following sections discuss the resolution of this concern.

The staff performed sample stability calculations with the LAPUR6 code to evaluate the impact of the TRACG three-dimensional momentum equation error. The issue is that the additional

pressure drop introduced by TRACG in the lower plenum is a single-phase pressure drop that tends to stabilize the reactor. This TRACG error is equivalent to non-physical increase in pressure drop to the channel inlet. It is well known that reducing the size (i.e., increasing the friction) of the channel inlet orifice is one of the best methods to stabilize the core.

The staff notes that the non-physical TRACG single-phase pressure drop applies mostly to the outlet of the downcomer, where the flow velocity is higher. Since the out-of-phase (regional) stability mode involves core flow redistribution in the lower plenum, the downcomer flow does not oscillate for regional oscillations; thus, this TRACG error will not significantly affect the regional decay ratio. Some effect will be present as TRACG overestimates the pressure drop caused by the radial component of the lower plenum flow, but this component contribution is small when compared to the vertical flow component contribution in the downcomer. The staff was concerned that the TRACG three-dimensional momentum equation error may significantly impact the stability of the corewide stability mode in the nonconservative direction. GEH's evaluation did not include this effect, so the staff then requested clarification in RAI 21.6-123 S01.

In response, GEH reiterated the root cause of the three-dimensional momentum equation formulation error. This error is a deficiency of the formulation, which does not take into account the momentum changes by vessel boundaries. The applicant performed a series of stability calculations as a function of lower plenum pressure drop. The applicant also simulated the pressure drop increases by adding an artificial friction factor to the lower plenum components. The resultant calculations indicate that increasing the lower plenum pressure drop has two competing effects: (1) the core flow is decreased, which has a conservative (destabilizing) effect, and (2) the channel inlet friction is increased, which has a nonconservative (stabilizing) effect. The two effects counteract one another, and the decay ratio does not vary significantly when the lower plenum friction is varied from a low to a higher value above the estimated pressure drop error.

The staff reviewed a series of scoping TRACE calculations, where the lower plenum friction was increased to result in an additional pressure drop. The TRACE calculations indicate the same trend as the applicant's TRACG calculations, and no significant effect is seen in the calculated decay ratio. Based on these analyses, the staff concludes that the decreased core flow and the increased channel inlet friction have competing effects and that the resulting net effect on the decay ratio calculated by TRACG is not affected significantly by the three-dimensional momentum equation formulation error. Thus, based on the applicant's response, RAI 21.6-123 is resolved.

21.6.3.2.17 Component Models

TRACG employs basic component models as building blocks to construct physical models for intended applications. Such an approach renders it a very general and flexible tool to simulate a wide variety of systems. The components that are modeled include pipe, pump, valve, tee, fuel channel, jet pump, steam separator, steam dryer, vessel, upper plenum, heat exchanger, and break and fill as boundary conditions. However, a turbine model for balance of plant simulation is missing. The heat exchanger model contains some simplifying approximations that may not be appropriate for simulating the IC or the condenser in balance of plant. However, GEH is not using the heat exchanger model for simulating either the PCCS or the ICS. TRACG has very sophisticated upper plenum, steam separator, and steam dryer models.

21.6.3.2.17.1 *Reactor Vessel*

TRACG models the reactor vessel using a three-dimensional VESSEL component. There is one VESSEL component in the LOCA model in which the lower numbered levels of the VESSEL represent the reactor vessel, and the higher numbered levels of the VESSEL represent the containment components. For modeling the reactor vessel, GEH includes channel components, channel bypass, the chimney, and the steam separators.

21.6.3.2.17.1.1 **Channel Components**

Because of code limitations on the maximum number of components, GEH could not model each channel individually in TRACG. Therefore, GEH combined the channels into groups. The following sections discuss channel grouping and nodalization for the specific ESBWR design-basis analyses.

LOCA

For LOCA applications, the TRACG input deck has three separate rings representing three channel groups within the VESSEL component. The staff finds this representation coarse for traditional LOCA analyses that require modeling of a hot channel. However, since none of the design-basis ESBWR LOCA events shows core uncover, the core does not heat up, and GEH did not calculate a PCT increase, thus making a more detailed channel representation unnecessary. The staff finds the GEH channel grouping acceptable for ESBWR LOCA applications. Stability, AOO/IE, and ATWS events require a more detailed channel representation.

Stability

For stability applications, a fine axial nodalization is used in the core entrance to attempt to maintain a constant Courant number and to provide more detailed modeling of the lower void regions of the core in which void oscillations have the greatest impact on stability. The staff finds the approach described in NEDE-32177P, Revision 3, to be acceptable.

The channel grouping depends on the type of calculation being performed. For corewide stability analysis, GEH examined the channel grouping described in Figure 5.2-4 of NEDE-33083P, Supplement 1. The staff found that the process for determining adequate channel grouping described in Section 8.1.2.2 of NEDE-33083P, Supplement 1, ensures that spatial variations are modeled adequately for stability analyses. Regional stability analyses require a different channel grouping to capture the character of higher flux harmonics. Figure 8.1-18 in NEDE-33083P, Supplement 1, depicts this channel grouping. The staff reviewed this procedure and determined that GEH had addressed these characteristics and that the procedure is adequate for modeling regional oscillations. The axial and radial nodalizations have been used in the past for TRACG calculations of operating reactor stability and have been found to be adequate for these calculations.

The SER for NEDE-33083P, Supplement 1, discusses the staff's review of the channel grouping and nodalization for ESBWR stability analyses in detail.

AOO/IE and ATWS

For the ESBWR AOO/IE and ATWS events, GEH used the same axial nodalization for the channel component as that used for the ESBWR stability analysis (NEDE-33083P, Supplement 1). GEH combines the channels based on similar hydrodynamic, as well as neutron kinetic, characteristics. The staff reviewed the GEH channel grouping to verify that it adequately represents the core design as described in NEDC-33239P, Revision 2, "GE14 for ESBWR Nuclear Design Report," issued April 2007. GEH represented the channels with the highest radial peaking factors as a single channel. In response to RAI 21.6-65, GEH provided a sensitivity study of the channel grouping for the load rejection with total bypass failure IE. GEH demonstrated that a case with more radial channels represented versus the radial grouping used for the licensing-basis ESBWR calculation produces virtually the same results, with the licensing-basis case producing $\Delta\text{CPR}/\text{ICPR}$ results that are more conservative. The staff finds that the GEH channel grouping for performing ESBWR AOO/IE and ATWS calculations as described in NEDE-33083P, Supplements 2 and 3, adequately represents the ESBWR core and is acceptable.

The staff requested information supplemental to RAI 21.6-65 on the channel grouping used for ESBWR AOO/IE evaluations. The staff asked whether GEH used only the hot channels for calculating the $\Delta\text{CPR}/\text{ICPR}$ because the staff was concerned that, although this is most conservative in many cases, for cold-water injection events, the $\Delta\text{CPR}/\text{ICPR}$ may be underestimated because the largest change in CPR would take place in the periphery channels. GEH responded to RAI 21.6-65 S01, by noting that the hot channel is always selected for the determination of the operating limit MCPR, because the core MCPR always occurs in the hottest channels. The response also shows MCPR calculations for the limiting cold water injection event. The results for the limiting channel in Ring 3 and the hottest bundle in Ring 2 are shown and compared. Although the decrease in $\Delta\text{CPR}/\text{ICPR}$ is greater in the Ring 3 channel, the MCPR in the hottest bundle is still limiting by a significant amount. The staff finds this response, and therefore the channel grouping for AOOs, to be acceptable. Based on the applicant's response, RAI 21.6-65 is resolved.

21.6.3.2.17.1.2 Chimney

LOCA

During the review of TRACG for ESBWR LOCA, GEH and the staff investigated nodalization and bundle power distributions on the calculated minimum water level in the chimney during a LOCA in the ESBWR.

The staff found that calculating the minimum water level for the ESBWR LOCA would be most appropriately represented by a single chimney partition. The staff reviewed the TRACG input decks for simulating LOCAs in the ESBWR for design certification and confirmed that GEH had added two individual chimney partitions. GEH used these components to calculate the minimum static head in the chimney.

Stability

In response to RAIs 4.4-11 and 4.4-12, GEH performed a series of detailed analyses of the effect of the chimney on two instability modes—density wave and loop instability. GEH modified the ESBWR TRACG model to include a fine node structure in the chimney region. For the cell

size selected by GEH, the time step is limited by the vapor velocity in the chimney (i.e., the Courant number is approximately 1).

The corewide power response to a pressure perturbation was evaluated with the new nodalization. The results were compared to the original (coarse chimney) results in Figure 4.4-11-2 in GEH's response to RAI 4.4-11. The traces are virtually indistinguishable, thus indicating that fine nodalization in the chimney has no effect on the core decay ratio.

Figure 4.4-11-3 in GEH's response to RAI 4.4-11 compares the core power response to a flow perturbation. Again, the responses for the coarse and fine nodalizations in the chimney closely agree.

Figure 4.4-11-5 in GEH's response to RAI 4.4-11 shows the results of a channel stability calculation for a high-power channel. The calculated results for the case with the finely nodalized chimney compare closely with the original calculation in NEDE-33083P, Supplement 1.

The staff concurs with the GEH evaluation that the finely nodalized chimney allows for a more accurate representation of void propagation through the chimney, but has no effect on the stability results.

Even though the GEH response to RAI 4.4-11 states that "The original nodalization used for the stability calculations in NEDE-33083P, Supplement 1 and the DCD is adequate for stability analysis," the staff believes that the TRACG model with the fine chimney nodalization should be used for future ESBWR stability calculations and issued RAI 4.4-58 S01. In the second part of the GEH's response to RAI 4.4-58 S01, the applicant justified the use of coarse nodalization in the chimney. The applicant's argument is that the chimney does not play an important role in the density-wave instabilities of interest. Loop oscillations (where the chimney plays an important role) are not limiting in the ESBWR and do not pose any significant safety concern. The applicant concluded that the coarse chimney nodalization is adequate for the ESBWR stability analysis.

After reviewing the available data, the staff finds that, for the density-wave oscillations that are likely to be limiting in the ESBWR, the chimney does not appear to play a significant dynamic role; thus, numerical damping in the chimney region is not likely to affect the magnitude of the calculated decay ratio. Therefore, the staff concurs with the applicant's evaluation and accepts that a coarse chimney nodalization is sufficient to model density-wave oscillations. Based on the applicant's response, RAIs 4.4-11, 4.4-12, and 4.4-58 are resolved.

21.6.3.2.17.1.3 Steam Separator

Since the GEH PIRT does not consider the steam separator to be important, it is modeled by a simple semi-empirical model. The model is based on the assumption that the vapor core has solid body rotation and the thin film has azimuthal velocity decaying as the inverse of the square root of the radial position. The model has four constants that are determined by comparing the prediction with the full-scale performance data.

21.6.3.2.17.2 *Isolation Condenser System*

The ICS provides additional liquid inventory to the RPV during a LOCA upon opening the condensate return valves to initiate the system. The ICS also provides the reactor with depressurization for AOO/IE and ATWS pressurization events such as an MSIV closure.

GEH performed a series of steady-state and transient IC tests and compared the data to TRACG simulations. The steady-state tests were performed to test the intended operation of the IC, such as condensing steam during a reactor isolation event. The transient tests simulated abnormal IC operations, including noncondensable gas buildup and a pool water level transient. The IC testing was performed at the PANTHERS-IC test facility. Section 4.2 of NEDC-32725P, Revision 1, describes the tests and the TRACG comparisons. Section 3.2 of MFN 04-059. The staff reviewed the results of these tests and the modeling of the ICS in the ESBWR TRACG input decks. RAI 21.6-55 asked a series of questions about the applicability of the ICS tests and the corresponding TRACG runs for the ESBWR.

The staff's review of the responses to RAI 21.6-55 and related supplements is discussed in detail in the SER for NEDE-33083P, Supplement 3.

One item related to RAI 21.6-55 that is not discussed in the staff SER for NEDE-33083, Supplement 3, is the capability of TRACG to model IC behavior when noncondensable gases are present for LOCA events. (The staff finds that TRACG is capable of modeling the IC behavior during AOO/ATWS and LOCA events for purely steam condensation.)

The staff agrees with GEH that it is not necessary to model noncondensable gases generated by radiolytic decomposition for ESBWR AOO/ATWS calculations because the IC is vented during normal operation and the duration of these transients is not long enough to generate these gases. For the most recent ESBWR LOCA analyses, the heat removal capacity of the ICS is not credited. Therefore, the ESBWR LOCA results are conservative and acceptable. Based on the applicant's response RAI 21.6-55 is resolved.

21.6.3.2.17.3 *Standby Liquid Control System Modeling*

The staff reviewed the GEH modeling of the SLCS for LOCA and ATWS applications. In RAI 21.6-12, the staff asked GEH to justify the velocity it selected for this component. This RAI is discussed in detail in the SER for NEDE-33083P, Supplement 2. The staff finds the SLCS modeling to be acceptable.

21.6.3.2.17.4 *Containment Components*

The SER within NEDC-33083P-A documents the staff's evaluation of TRACG for containment analysis. However, the TRACG model nodalization has been modified to incorporate the design changes, additional features, and finer details compared to the one used in its preapplication review. For ESBWR LOCA applications, GEH combined the detailed RPV and the detailed containment model into a single consistent input deck. The same deck is exercised for both containment and water-level calculations. The air gap between the reactor shield wall and the pressure vessel is also modeled in the combined TRACG nodalization. The RPV wall is modeled as a lumped heat slab. The combined TRACG model results compared well with those from the base cases, and the impacts due to nodalization changes on the minimum chimney static head level and the long-term drywell pressure are judged to be small compared to the margins. The TRACG model is currently set for 4,500-MW core power. DCD Tier 2,

Revision 4, Tables 6A-1 and 6.2-6a and Appendix 6B, document these design and modeling changes. Section 6.2.1 of this report presents the staff's evaluation of these changes.

Section 4.0 of the staff SER within NEDC-33083P-A includes 20 confirmatory items that were identified as needing resolution at the design certification stage. The staff's evaluation of these confirmatory items appears in the Addendum to the SER for NEDE-33083P-A. As discussed in the Addendum to the SER for NEDC-33083P-A, all of the confirmatory items are closed.

The following sections describe the various TRACG containment components and their TRACG treatment. The staff is evaluating the adequacy of the containment models for calculating containment peak pressure as discussed in Section 6.2 of this report.

21.6.3.2.17.4.1 Wetwell

The wetwell consists of the SP and wetwell gas space. The wetwell is bounded by the diaphragm floor on top, containment outer wall, and wetwell inner wall on the sides and the floor of the containment. During blowdown, flow from the safety/relief valves (SRVs) is directed to the SP and quenched via the safety relief valve (SRV) discharge lines. Flow from the LOCA break and DPVs is directed from the drywell to the SP and quenched via the SP horizontal vent system. Any flow through the PCC vents is also discharged to the SP.

Wetwell Gas Space

The wetwell gas (steam and noncondensables) space is also represented by multidimensional cells. Typically, rings and axial levels are employed in the TRACG model, which allows for natural circulation in this region. The flow regimes in this region will be the same as in the drywell—single-phase gas, dispersed droplets resulting from entrainment from the SP, and a condensate film on the walls. The models involved in the calculation include turbulent shear between cells, noncondensable distribution, wall friction, interfacial friction, wall heat transfer, fogging and interfacial heat transfer, and heat transfer at the SP interface.

Suppression Pool

The SP is also represented by multidimensional cells. Rings and axial levels are used to represent the pool. The major phenomena of interest for the SP include steam condensation with or without noncondensable gases, temperature distribution, thermal stratification, and pool two-phase level.

21.6.3.2.17.4.2 Passive Containment Cooling Pools

The six PCC pools are located outside (above) the containment. The total PCCS cooling capacity is 66 MW. Each pool contains one PCC unit. The pools are interconnected with each other and with the IC pools.

The pools are represented as part of the three-dimensional TRACG region, partitioned into the IC and PCC pools. The pools are allowed to communicate with each other at the bottom and the top. The pools are modeled with rings and axial levels. Heat transfer occurs from the PCC headers and tubes to the water in the pools. Pool side heat transfer is calculated using correlations either as boiling heat transfer or as single-phase convection to liquid for subcooled conditions. The staff reviewed the pool heat transfer correlations used for both boiling heat

transfer and single-phase convection to liquid and found them acceptable for this application. The staff's SER within NEDC-33083P-A documents this review.

21.6.3.2.17.4.3 Passive Containment Cooling Units

The ESBWR has six PCC heat exchanger units. Each comprises two-module drum and tube heat exchangers using horizontal upper and lower drums connected with a multiplicity of vertical tubes (280 tubes per module). Two identical modules are coupled to form one PCC heat exchanger unit. One-dimensional components simulating the inlet piping, headers, condenser tubes, condensate discharge lines, and ventlines, represent the PCC units. One-dimensional forms of the mass, momentum, and energy equations are applicable. Heat is transferred through the walls of the tubes and headers to the respective pools.

The PCCS can operate in two distinct modes—a condensation mode and a pressure differential mode. In the condensation mode, the steam is condensed in the vertical tubes and the condensate is drained from the lower drum to the individual unit's drain tank. In the pressure differential mode, the flow through the PCC heat exchangers is caused by a drywell-wetwell pressure difference, since the PCC ventline outlet is higher than the outlet of the upper horizontal drywell/wetwell LOCA vents. Noncondensable gases and uncondensed steam are vented to the SP. The staff reviewed the correlation for calculating heat transfer inside the tubes as well as the configuration of the PCCS, and found them acceptable for this application. The staff's SER within NEDC-33083P-A documents this review.

21.6.3.2.17.4.4 Horizontal Vent System

The ESBWR has 36 horizontal vents between the drywell and the SP. The 12 vertical flow channels each contain three horizontal vents attached to a vertical vent pipe. The top row of horizontal vents is approximately 0.9 m (2.95 ft) below the bottom of the PCC vents. The remaining two rows of vents are each vertically separated by 1.37 m. (4.49 ft) GEH models the horizontal vents in TRACG. The staff's SER within NEDC-33083P-A documents the review of the horizontal vents.

21.6.3.2.17.4.5 Gravity-Driven Cooling System Equalizing Lines

As described in ESBWR DCD Tier 2, Revision 9, Section 6.3.2.7.1, four GDCS equalizing lines (one per division) connect the SP to the RPV downcomer. During the long-term cooling phase of the post-LOCA transient, the squib valves in these lines will open if the RPV level in the downcomer drops to 1 m (3.28 ft) above the top of the active fuel or 8.453 m (27.733 ft) from the RPV bottom, with a 30-minute delay time to create a permissive signal. These valves do not actuate during any design-basis LOCA event for 72 hours. The TRACG model for an ESBWR LOCA contains a model for the equalizing lines. The correlations used for wall friction and singular losses are the same as used for the horizontal vents. The staff's SER within NEDC-33083P-A documents the review of the GDCS equalizing lines.

21.6.3.2.17.4.6 Vacuum Breakers

The ESBWR has three VBs connecting the upper drywell to the wetwell gas space. The VBs will open when the pressure in the wetwell exceeds that of the drywell by a specified value. The VBs are represented by one-dimensional VALVE components. The VBs are lumped together as one component and are triggered open at a set negative pressure differential between the drywell and wetwell. They will close at a lower value of the pressure differential. The VBs

transport flow from the wetwell gas space to the drywell at conditions corresponding to the cell in the wetwell gas space to which they are connected.

The correlations used for the singular losses are the same as for the horizontal vents. The staff's SER within NEDC-33083P-A documents the review of the vacuum breakers.

21.6.3.2.17.4.7 Reactor Pressure Vessel Level versus Minimum Containment Pressure

During the December 2006 audit, the staff and GEH discussed the use of the TRACG containment model in the RPV-level calculation. The staff was concerned that the containment portion of the input deck was designed with assumptions to give maximum containment pressure, which may be nonconservative for RPV-level calculations, as historical operating plant analyses have been performed with minimum containment pressure. At that time, no conclusion was reached as to the impact that the minimum containment pressure would have on the ESBWR RPV-level calculation. The staff addressed this issue in RAI 6.2-144. In response, GEH evaluated the impact of containment back pressure on the ECCS performance and updated the results in ESBWR DCD Tier 2, Revision 4, Appendix 6C. The staff reviewed GEH's evaluation and determined that the minimum chimney collapsed level is not sensitive to the changes in the containment back pressure expected for the ESBWR design under LOCA conditions. Based on the applicant's response, RAI 6.2-144 is resolved.

21.6.3.2.17.4.8 TRACG Modeling of Steam Source

During a December 2006 audit, GEH provided the results of sensitivity studies in which it examined the effects of placing the steam source at different elevations of the drywell. GEH showed that the highest peak pressure results from placing the steam source at the highest elevation. The staff noted that these results are inconsistent with the current GEH practice of placing the steam source below the RPV. GEH addressed this particular issue in response to RAI 6.2-53 S01. In its response, GEH showed sensitivity analyses results to confirm that the current bounding MSLB case where the break occurs at Level 34 is limiting. For calculations in ESBWR DCD Tier 2, Revision 2, GEH has used an MSLB break location at Level 23, which the staff showed as not conservative during the December 2006 audit. As a result, GEH has changed the MSLB break location to Level 34 in ESBWR DCD Tier 2, Revision 3. Based on the applicant's response, RAI 6.2-53 S01, including all supplemental questions for that RAI, is resolved.

21.6.3.3 Accident Scenario Identification Process

The behavior of a nuclear power plant undergoing an accident or transient is not influenced equally by all phenomena that occur during the event. Those phenomena that are important for each event and the various phases within an event must be determined. Development of a PIRT establishes those phases and phenomena that are significant to the progress of the event being evaluated.

21.6.3.3.1 Loss-of-Coolant Accident

Important phenomena for LOCAs in the ESBWR have been identified in two PIRTs—LOCA/ECCS and LOCA/containment. The PIRT for LOCA/ECCS includes all the high- and medium-ranked phenomena in the RPV, main steamlines, and ICS, including system interactions. The PIRT for LOCA/containment covers all the high- and medium-ranked phenomena in the drywell, wetwell, GDCS, PCCS, DPVs, VBs, main vents (between the drywell

and wetwell), and SRV quenchers. A team of experts conducted both top-down and bottom-up processes to obtain these phenomena, which were later used for TRACG assessment.

The two PIRTs were further evaluated and revised according to the results of the scaling analysis. The revision either confirmed or downgraded, with few exceptions, the ranking of some high-ranked phenomena. However, the revision upgraded several events to high-ranked phenomena, including the addition of the mass flow through the break during the GDSCS injection and long-term cooling phases of the LOCA, mass flow through the SRVs/DPVs during the GDSCS injection phase of the LOCA, flashing/redistribution in the control rod guide tube region, and flashing in the downcomer annulus during the GDSCS injection phase of the LOCA.

The staff found the PIRT for the ESBWR LOCA acceptable because the assessment of the code included all of the high- and medium-ranked phenomena. NEDC-33083P-A includes more details of the staff's review of the PIRT for LOCA.

21.6.3.3.1.1 *Loss-of-Coolant Accident Long-Term Core Cooling*

DCD Appendix 6G, provides details on long-term core cooling. The section discusses long-term inventory distribution for four break locations—(1) MSLB, (2) FWLB, (3) BDLB, and (4) GDSCS line break.

GEH provided a PIRT related to long-term core cooling of the ESBWR. The phenomena that ranked high for the MSLB and FWLB were decay heat, GDSCS pool volume versus elevation, and RPV volume versus elevation. GEH gave PCCS capacity a ranking of medium for these events. The phenomena that ranked high for the BDLB and GDSCS line break were decay heat, DPVs (break flow and pressure drop), PCCS capacity, lower drywell volume versus elevation, GDSCS pool volume versus elevation, and RPV volume versus elevation.

The staff's Addendum to the SER for NEDE-33083P-A provides more details of the staff's review of the long-term core cooling PIRT. The staff finds the GEH PIRT acceptable for demonstrating long-term core cooling of all LOCA cases, and all important components are modeled.

21.6.3.3.2 Stability

A PIRT identified important phenomena for stability in the ESBWR. The PIRT for stability includes all the high- and medium-ranked phenomena. The staff found the stability PIRT to be comprehensive, giving the appropriate ranking to stability phenomena. The staff's SER for NEDE-33083P, Supplement 1 contains the details of the staff's review of the PIRT for ESBWR stability.

21.6.3.3.3 Anticipated Operational Occurrences/Infrequent Events

GEH identified important phenomena for AOOs in the ESBWR in a PIRT. The transient events have been categorized into three groups—(1) pressurization events, (2) depressurization events, and (3) cold-water insertion events. For each event type, the phenomena are listed and ranked for each major component in the reactor system. The staff's review of the AOO PIRT is in the SER for "Application of the TRACG Computer Code to the Transient Analysis for the ESBWR Design."

In RAI 21.6-61, the staff questioned why mixing in the lower plenum for cold-water injection events was not ranked as high. The staff's concern was that as cold water enters the core, it might not mix well in the lower plenum, and there may be areas of concentrated cold water causing a pronounced effect on ΔCPR for bundles in this location. The staff was concerned that the impact on ΔCPR would be greater than that calculated by TRACG because of the coarse noding of the lower plenum in the ESBWR TRACG model at the time that RAI 21.6-61 was transmitted. A PIRT ranking of high would ensure that the uncertainties associated with lower plenum mixing are included in the calculation of ΔCPR .

The GEH response to RAI 21.6-61 included a nodalization study of the feedwater controller failure (FWCF) event, in which it increased and decreased the rate of transfer between the radial rings in the lower plenum by artificially creating resistance between these cells. GEH showed the ultimate change in ΔCPR , given that the different resistances in the lower plenum did not have a substantial effect on ΔCPR for Ring 1 (the most central) and Ring 2 (next to the most central). GEH did not display the results of the ΔCPR changes for Ring 3, which is the outermost ring and the one of greatest concern.

Subsequent to the GEH response to RAI 21.6-61, the ESBWR DCD, as well as NEDE-33083, Supplement 3, shows that the PIRT ranking for lower plenum mixing is high, and the TRACG AOO methodology for the ESBWR accounts for the corresponding uncertainty. In addition, a computational fluid dynamics study performed by the staff for the limiting cold-water injection event cold-water transient shows that the thermal mixing at the side entry orifices (which is representative of the mixing that occurs in the downcomer and lower plenum) is consistent with the results from the TRACG model. Therefore, RAI 21.6-61 is closed.

21.6.3.3.4 Anticipated Transient without Scram

GEH identified important phenomena for ATWS in the ESBWR in a PIRT. The phenomena are identified as having an effect on three critical safety parameters—(1) SP temperature, (2) vessel pressure, and (3) fuel clad temperature.

In ranking the phenomena, GEH divided the limiting scenarios into five phases—(1) short-term pressurization, neutron flux increase, and fuel heatup, (2) feedwater runback and water-level reduction, (3) boron injection, mixing, and negative reactivity insertion, (4) post-shutdown SP heatup, and (5) depressurization of the reactor.

The ESBWR ATWS PIRT builds on the ESBWR AOO PIRT. Several PIRT parameters were introduced specifically for the ESBWR ATWS evaluation, including the following:

- ATW1: boron mixing/entrainment between the jets downstream of the injection nozzle
- ATW2: boron settling in the guide tubes or lower plenum
- ATW3: boron transport and distribution through the vessel, particularly in the core bypass region
- ATW5: boron reactivity

The staff finds that the ATWS PIRT is comprehensive and gives the appropriate rating to the phenomena important for ESBWR ATWS. The staff's SER for NEDE-33083P, Supplement 2 discusses the staff's review in detail.

21.6.3.4 Code Assessment

The staff reviewed the following assessment cases that were analyzed using TRACG04:

- Separate effects, component, and integral tests
 - Toshiba low-pressure tests
 - Ontario Hydro large-diameter tests
 - PANTHERS/PCCS tests
 - PANTHERS/ICS tests
 - SP
 - FIST low-pressure coolant injection break results
 - GIRAFFE systems interaction (GS1) test
 - GIRAFFE/helium test
 - ROSA-IV LOCA tests
 - One-sixth-scale boron mixing
 - PSTF containment response tests
 - FIX-II LOCA tests
 - PANDA transient tests
- Plant data
 - Dodewaard startup (natural circulation)
 - Peach Bottom stability tests
 - NMP-2 instability event

The staff audited these assessments. The staff has reviewed other tests as part of the TRACG review, and these reviews are documented in other sections of this report, as well as in NEDC-33083P-A, the SER for NEDE-33083P, Supplement 1,, and the SER for NEDE-32906P, Supplement 3. The staff confirms that GEH has extensively qualified TRACG04 and that TRACG04 adequately predicts all highly ranked behavior.

The staff requested in RAI 21.6-75 that GEH provide the TRACG04 version used to perform analysis of all ESBWR LOCA events in the design certification documentation. In response, GEH submitted Revision 3 of the ESBWR qualification report (NEDE-32177P). The staff reviewed the GEH qualification of its void fraction data provided in this report to ensure that the modifications to the entrainment fraction and its subsequent use in the interfacial shear model compare well with the data. The void fraction assessment results from NEDE-32177P, Revision 3, are very close to the results from NEDE-32177P, Revision 2, which was assessed as satisfactory during the ESBWR preapplication phase of the ESBWR design certification review. This ensures that the conclusion from the preapplication TRACG review is still valid. In addition, NEDE-32177P, Revision 3, adds assessment cases which include Toshiba Low-Pressure Void Fraction Tests, Ontario Hydro Void Fraction Tests, and CISE Density Measurement Tests. The Toshiba tests were added to extend the qualification basis to lower pressures at 0.5 and 1.00 MPa (72.5 and 145 psi). The Ontario Hydro facility provides void fraction data from a large-scale pumped flow facility. The CISE facility in Italy provided data related to the void and quality relationship. The TRACG assessment showed good agreement with the data from those tests. The assessment from NEDE-32177P, Revision 3, reinforced the conclusion from the NEDC-33083P-A that the interfacial shear model is acceptable. Based on the applicant's response, RAI 21.6-75 is resolved.

21.6.3.5 Uncertainty Analysis

21.6.3.5.1 Loss-of-Coolant Accident

In a letter dated September 9, 2005, "Summary of September 9, 2005 NRC/GE Conference Call on TRACG LOCA SER Confirmatory Items," GEH stated that since there is no core heatup, an uncertainty analysis of PCT would not provide useful results. GEH further stated that a bounding evaluation for the minimum water level in the chimney during a LOCA event would demonstrate that there is margin to core uncover and heatup. As stated in 10 CFR 50.46(a)(1)(i), "comparisons to applicable experimental data must be made and uncertainties in the analysis method and inputs must be identified and assessed so that the uncertainty in the calculated results can be estimated. This uncertainty must be accounted for...." Furthermore, 10 CFR 50.46(a)(1)(ii) states, "Alternately, an ECCS evaluation model may be developed in conformance with the required and acceptable features of Appendix K ECCS Evaluation Models." The staff issued RAI 6.3-81 requesting that GEH demonstrate how the LOCA analyses comply with this requirement. GEH responded by stating that, because there is no core uncover and no core heatup for the ESBWR LOCAs, a statistical analysis of the PCT serves no useful purpose. The best estimate PCT and the 95/95 PCT would both be close to the saturation temperature corresponding to the peak steam dome pressure reached in the accidents. For the case of ESBWR LOCAs, there is a margin of over 871.1 degrees C (1,600 degrees F) to the limit of 1204.4 degrees C (2,200 degrees F) (acceptance criteria set forth in paragraph (b) of 10 CFR 50.46). GEH further commented that the static head inside the chimney (in meters of water) is selected as the figure of merit for comparison and for evaluating the impact of uncertainties in model parameters and plant parameters. This collapsed level is defined as the equivalent height of water corresponding to the static head of the two-phase mixture above the top of the core. NEDC-33083P-A, Sections 2.4 and 2.5.3, identify the TRACG model parameter uncertainties and plant parameter uncertainties. Sensitivity studies were performed by varying each of these parameters from the lower bound to the upper bound value. The impact on the chimney static head is between -0.3 m to +0.2 m (-0.98 to +0.66 ft) (NEDC-33083P-A, Section 2.4.4.2), which is less than the minimum static head in the chimney from the parametric studies. Therefore, GEH proposed that a simple calculation be made, setting the most significant parameters at the 2-sigma values to obtain a bounding estimate of the minimum level.

The staff concurs that the ESBWR LOCA results demonstrate a high level of probability that there is no core uncover or heatup and that the PCT would be close to the saturation temperature corresponding to the peak steam dome pressure reached in the accidents and therefore would not exceed the acceptance criteria of 10 CFR 50.46. The staff concludes that GEH's LOCA results comply with the requirement of 10 CFR 50.46. Based on the applicant's response, RAI 6.3-81 is resolved.

21.6.3.5.2 Stability

GEH accounts for the uncertainty in the stability calculations in two ways. First, for the ESBWR, it sets the design criteria for the decay ratio to 0.8 to allow 0.2 in uncertainty. In addition, GEH statistically combines the uncertainty of all of the medium and highly ranked phenomena. GEH chose the normal distribution, one-sided upper tolerance limit (ND-OSUTL) method if the output distribution is normal; otherwise, GEH used the order statistics method. The staff reviewed and accepted the 1-sigma uncertainty values of the high- and medium-ranked parameters, which are discussed in the SER for NEDE-33083P, Supplement 1. The staff reviewed the uncertainties in

the physics parameters as part of design certification; the Addendum to the SER for NEDE-33083P, Supplement 1, discusses these uncertainties.

21.6.3.5.3 Anticipated Operational Occurrence/Infrequent Event

For the TRACG application for ESBWR AOO analysis described in NEDE-33083P, Supplement 3, GEH used the same method for determining combined bias and uncertainty as is used in the GEH application of TRACG to the BWR/2–6 AOO analysis (NEDE-32906P, Revision 2). The staff previously reviewed this method in detail and accepted it for the application of TRACG to BWR/2–6 AOO analyses. The associated SER documents the staff's review for BWR/2–6 AOO analyses.

For the ESBWR AOO analyses in NEDE-33083P, Supplement 3, GEH either bounds or accounts for the uncertainty of all high- and medium-ranked PIRT parameters. For parameters for which uncertainty is accounted, GEH chose the ND-OSUTL method if the output distribution is normal and used the order statistics method if the output distribution is not normal. The SER for NEDE-33083P, Supplement 3, presents the staff's review of TRACG for ESBWR AOO analyses. The staff finds the use of this methodology acceptable for determining the combined uncertainty for TRACG modeling of the ESBWR AOO events.

21.6.3.5.4 Anticipated Transient without Scram

The method that GEH uses to combine uncertainties for the ESBWR ATWS events is different than the method used for the analysis of other events. For the ESBWR ATWS analyses in NEDE-33083P, Supplement 2, GEH either bounds or accounts for biases and uncertainties for all high-ranked PIRT parameters. For the parameters with uncertainty accounted for, the propagation of errors method is used to combine uncertainties.

The staff has reviewed this method and finds it acceptable for determining the combined uncertainty for TRACG modeling of ESBWR ATWS events. The SER for NEDE-33083P, Supplement 2, discusses the staff's review in greater detail.

21.6.4 Staff Calculations

The staff made independent calculations of ESBWR events using the TRACE thermal-hydraulic code coupled to the PARCS neutronic code. The models were developed using ESBWR design information.

The staff has performed confirmatory calculations for the LOCA water-level events and documented the results in Section 6.3 of this SER. The confirmatory calculations show that the key parameter responses during LOCA by GEH are reasonable and the core remains covered with water in all LOCA analyses.

21.6.5 Conclusions

The staff reviewed the TRACG code based on the review guidelines of SRP Section 15.0.2, issued December 2005. The evaluation covered required documentation: (1) the evaluation models, (2) the accident scenario identification process, (3) the code assessment, (4) the uncertainty analysis, (5) a theory manual, (6) a user manual, and (7) the QA program. The staff concludes that TRACG, including the application methodology, is an acceptable evaluation model for ESBWR LOCAs, AOOs/IEs, ATWS, and stability. These methods must follow the

application procedures outlined in the associated topical reports and adhere to the NRC conditions and limitations specified in the staff SERs.

21.7 Quality Assurance Inspection

The staff relied on four principal test programs (PANDA, PANTHERS/PCCS, PANTHERS/ICS, and GIRAFFE) to demonstrate that analytical methods and computer codes described in this chapter were adequately and appropriately applied in ESBWR accident analyses. The purpose of the test programs was to validate the capability of accident analysis computer models to predict plant thermal-hydraulic behavior for a variety of accident conditions. These test programs were originally conducted to support the design certification application for the SBWR design.

During the 1994–1996 timeframe, the staff conducted QA program implementation inspections of GEH's major SBWR design certification thermal-hydraulic test programs used in the design and licensing of the SBWR. The staff conducted these inspections to determine if GEH and its contractors/partners had fulfilled GEH's commitment to its DCD, Chapter 17 QA requirements. ESBWR DCD Tier 2, Revision 9, Section 1.5, and Section 21.3 of this report describe these test programs in detail. The NRC inspections of the GEH test programs resulted in the identification of findings (Notice of Nonconformance and Unresolved Items) for failure to adequately implement QA program requirements, procedural requirements, and testing activities in certain cases. GEH described the corrective actions taken in its responses to these NRC inspection findings. The staff accepted these responses and corrective actions as responsive to the NRC inspection findings.

As described in Chapter 17.0 of this report, the applicant has continuously maintained a QA program that meets the requirements of Appendix B to 10 CFR Part 50 and spans SBWR and ESBWR design activities. Because testing activities used to confirm the validity of safety-related analytical methods and computer codes are within the scope of Appendix B QA requirements, the staff reviewed the QA program controls applied to testing activities. Specifically, the staff verified that test facilities implemented QA controls that meet the requirements of the applicant's QA program and Appendix B to 10 CFR Part 50 during the SBWR design certification review. As part of the QA review, the staff reviewed the QA program used at each of the test facilities and performed inspections to verify that the quality program was effectively implemented. The last of these inspections was performed at PANDA in 1996. For each of the four SBWR test programs, the staff concluded that reasonable and appropriate QA measures were used to control SBWR test activities. (See resolution of Unresolved Item (URI) 05200010-2005-201-02 below.)

As part of its review of DCD Tier 2, Chapter 17, the staff inspected the implementation of the GEH QA program for ESBWR activities. The staff performed these inspections in November 2005, April 2006, and December 2006. The following describe the findings:

- David B. Matthews (NRC) to David H. Hinds (GENE), "NRC Inspection Report 05200010/2005-201 and Notice of Nonconformance," January 11, 2006.
- David B. Matthews (NRC) to David H. Hinds (GENE), "NRC Inspection Report 05200010/2006-201 and Notice of Nonconformance," June 14, 2006.

- David B. Matthews (NRC) to David H. Hinds (GENE), "NRC Inspection Report for General Electric Nuclear Energy (GENE) General Economic and Simplified Boiling Water Reactor (ESBWR) Quality Assurance Implementation Follow-up Inspection," January 19, 2007.

As part of the November 2005 inspection, the staff identified URI 05200010-2005-201-02 concerning the previous SBWR Qualification Test Program Quality Assurance Inspections. This URI requested that GEH recapture all the inspection documentation records related to the GEH design certification testing programs performed for the SBWR that are also being used to support design certification of the ESBWR.

GEH responded in the following letters:

- David H. Hinds (GENE) to NRC Document Control Desk, "Reply to Notice of Nonconformance NRC Inspection Report 05200010/2005-201, dated January 11, 2006," February 9, 2006.
- David H. Hinds (GENE) to NRC Document Control Desk, "NRC Inspection 05200010/2005-201 Unresolved Items," dated October 27, 2006. This response described the quality oversight activities that had been performed and identified the NRC and GEH documentation supporting the SBWR test program inspections.
- David H. Hinds (GENE) to NRC Document Control Desk, "NRC Inspection 05200010/2005-201 Unresolved Items," dated October 27, 2006, Enclosure 2, "Quality Oversight for the SBWR Test Program." This enclosure included the description and identification of the oversight documentation for the PANDA, PANTHERS/PCCS, PANTHERS/ICS, and GIRAFFE test programs. Based on review of the documentation supplied by GEH, the staff closed URI 05200010-2005-201-02.

21.8 Conclusions

Because the accident analysis computer models have not changed since they were originally validated during the SBWR design certification review, the staff concludes that the previous QA test program reviews conducted to support SBWR design certification generally remain valid for the ESBWR design. After considering the QA implementation inspections of GEH's design certification test facilities and programs, the staff concludes that the QA programs governing GEH's SBWR/ESBWR design certification test programs satisfy the requirements of 10 CFR Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants," and the pertinent provisions of Appendix B to 10 CFR Part 50.

22.0 REGULATORY TREATMENT OF NONSAFETY SYSTEMS

22.1 Introduction

This section of the ESBWR safety evaluation report (the report) addresses the regulatory treatment of nonsafety systems. Unlike the current generation of light-water reactors or the evolutionary advanced light-water reactors (ALWRs), the economic simplified boiling-water reactor (ESBWR) plant design uses passive safety systems that rely almost exclusively on natural forces, such as density differences, gravity, and stored energy, to supply safety injection water and provide core and containment cooling. These passive systems do not include pumps; however, they do include some active valves. All safety-related active valves require direct current (dc) safety-related electric power (supplied by batteries), are air operated (and fail safe on loss of air), or are check valves. The ESBWR design does not include any safety-related sources of alternating current (ac) power for the operation of passive system components. All active systems (i.e., systems requiring ac power to operate) are designated as non-safety-related, except for the instrumentation and control systems, which use safety-related ac power converted from safety-related dc power.

Because the ESBWR relies on passive safety systems to perform the design-basis, safety-related functions of reactor coolant makeup and decay heat removal, different portions of the passive systems also provide certain defense-in-depth backup to the primary passive features. For example, while the passive isolation condenser system (ICS) is the primary safety-related heat removal feature in a transient that does not result in a loss of coolant, the automatic depressurization system (ADS), together with passive safety injection features, provides a safety-related, defense-in-depth backup.

The ALWR Utility Requirements Document (URD) for passive plants, issued by the Electric Power Research Institute (EPRI) in 1992, includes standards related to the design and operation of active, nonsafety-related systems. The URD recommends that the plant designer specifically define the active systems relied upon for defense-in-depth and necessary to meet passive ALWR plant safety and investment protection goals. Defense-in-depth systems provide long-term, postaccident plant capabilities. Passive systems should be able to perform their safety functions independent of operator action or offsite support for 72 hours after an initiating event. After 72 hours, nonsafety or active systems may be required to replenish the passive systems or to perform core and containment heat removal duties directly. The ESBWR includes active systems that provide defense-in-depth (or investment protection) capabilities for reactor coolant system makeup, decay heat removal, and containment heat removal. These active systems are the first line of defense in reducing challenges to the passive systems in the event of transients or plant upsets. As noted above, most active systems in the ESBWR are designated as nonsafety-related.

Examples of nonsafety-related systems that provide defense-in-depth capabilities for the ESBWR design include the fuel and auxiliary pools cooling system (FAPCS), control rod drive (CRD) system injection function, reactor water cleanup/shutdown cooling (RWCUS/SDC) system, and the reactor component cooling water system (RCCWS). For these defense-in-depth systems to operate, the associated systems and structures to support these functions must also be operable, including nonsafety-related standby diesel generators (DGs) and the plant service water system (PSWS). The ESBWR includes other active systems, also designated as nonsafety-related, such as the heating, ventilation, and air conditioning (HVAC) system that removes heat from the instrumentation and control cabinet rooms and the main control room

(MCR). These systems also prevent the excessive accumulation of radioactive materials in the control room to protect control room personnel.

In existing plants, as well as in the evolutionary ALWR designs, many of these active systems are designated as safety-related. However, by virtue of their designation in the ESBWR design as nonsafety-related, the licensing design-basis transient analyses described in ESBWR design control document (DCD), Tier 2, Revision 9, Section 15, do not model active systems (except in certain cases in which operation of a nonsafety-related system could make a transient worse). In SECY-90-406, "Quarterly Report on Emerging Technical Concerns," dated December 17, 1990, the staff of the U.S. Nuclear Regulatory Commission (NRC) listed the role of these active systems in passive plant designs as an emerging technical issue. In SECY-93-087, "Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor Designs," dated April 2, 1993, the staff discussed the issue of the regulatory treatment of nonsafety systems (RTNSS) and stated that it would propose a process for the resolution of this issue in a separate Commission paper. The staff subsequently issued SECY-94-084, "Policy and Technical Issues Associated with the Regulatory Treatment of Nonsafety Systems in Passive Plant Designs," dated March 28, 1994, which discusses that process. In SECY-95-132, "Policy and Technical Issues Associated with the Regulatory Treatment of Nonsafety Systems in Passive Plant Designs," dated May 22, 1995, the staff essentially revised SECY-94-084 to respond to Commission comments on that paper and to request Commission approval of certain revised positions. However, the Commission approved the staff's position on RTNSS as discussed in SECY-94-084 in a staff requirements memorandum (SRM) dated June 30, 1994; this position remained unchanged in SECY-95-132.

In SECY-94-084, the staff cited the uncertainties inherent in the use of passive safety systems resulting from limited operational experience and the relatively low driving forces (e.g., density differences and gravity) in these systems. The uncertainties relate to both system performance characteristics (e.g., the possibility that check valves could stick under low differential pressure conditions) and thermal-hydraulic phenomena (e.g., critical flow through ADS valves). In some cases, design enhancements addressed the system performance issues. For example, designers improved check valve performance by using normally open check valves in the gravity-driven cooling system (GDACS) discharge lines. In addition, GE-Hitachi (GEH or the applicant) addressed uncertainties associated with passive system reliability, as well as thermal-hydraulic uncertainties, by virtue of the test programs reviewed and approved by the staff in the pre-application phase of the NRC review and as discussed in Section 21 of this report.

The residual uncertainties associated with passive safety system performance increase the importance of active systems in providing defense-in-depth functions to back up the passive systems. Recognizing this, the NRC and EPRI developed a process to identify important active systems and to maintain appropriate regulatory oversight of those systems. This process does not require that the active systems brought under regulatory oversight meet all safety-related criteria, but rather that these controls provide a high level of confidence that active systems having a risk-significant role are available when they are challenged.

The ALWR URD specifies standards concerning the design and performance of active systems and equipment that perform nonsafety-related, defense-in-depth functions. These standards include radiation shielding to permit access after an accident, redundancy for the more probable single active failures, availability of nonsafety-related electric power, and protection against more probable hazards. The standards also address realistic safety margin analysis and testing to demonstrate the systems' capabilities to satisfy their nonsafety-related, defense-in-depth

functions. However, the ALWR URD does not include specific quantitative standards for the reliability of these systems.

SECY-94-084 and SECY-95-132 describe the scope, criteria, and process used to determine RTNSS for the passive plant designs. The staff has incorporated this information into Regulatory Guide (RG) 1.206, "Combined License Applications for Nuclear Power Plants," issued June 2007.

The following five key elements make up the RTNSS process:

1. The ALWR URD describes the process to be used by the designer to specify the reliability/availability (R/A) missions of risk-significant structures, systems, and components (SSCs) needed to meet regulatory requirements and to allow comparisons of these missions to NRC safety goals. An R/A mission is the set of requirements related to the performance, reliability, and availability of an SSC function that adequately ensures the accomplishment of its task, as defined by a focused probabilistic risk assessment (PRA) or deterministic analysis.
2. The designer applies the process to the design to establish R/A missions for the risk-significant SSCs.
3. If active systems are determined to be risk significant, the staff reviews the R/A missions to determine whether they are adequate and whether the operational reliability assurance process or technical specifications (TS) can provide reasonable assurance that the missions can be met during operation.
4. If active systems are relied upon to meet the R/A missions, the designer imposes design requirements commensurate with the risk significance of those elements involved.
5. A design certification rule will not explicitly state the R/A missions for risk-significant SSCs. Instead, the rule will include deterministic requirements for both safety-related and nonsafety-related design features.

The following two sections discuss the steps of the RTNSS process to address the five key elements described above.

22.2 Scope and Criteria for the Regulatory Treatment of NonSafety Systems Process

The RTNSS process applies broadly to those nonsafety-related SSCs that perform risk-significant functions and therefore are candidates for regulatory oversight. The RTNSS process uses the following five criteria to determine those SSC functions:

1. SSC functions relied upon to meet deterministic NRC performance requirements, such as Title 10 of the *Code of Federal Regulations* (10 CFR) 50.62 and 10 CFR 50.63;
2. SSC functions relied upon to ensure long-term safety (beyond 72 hours) and to address seismic events;

3. SSC functions relied upon under power-operating and shutdown conditions to meet the Commission's safety goal guidelines of a core damage frequency (CDF) of less than 1×10^{-4} per reactor year and a large release frequency (LRF) of less than 1×10^{-6} per reactor year;
4. SSC functions needed to meet the containment performance goal, including containment bypass, during severe accidents; and
5. SSC functions relied upon to prevent significant adverse systems interactions.

Regarding Criterion 4, the staff discussed this issue in detail in SECY-93-087. For the ESBWR, the criterion for assessing containment performance is the degree to which the design comports with the Commission's probabilistic containment performance goal of less than 0.1 conditional containment failure probability (CCFP) when no credit is provided for the performance of the nonsafety-related, defense-in-depth systems for which there will be no regulatory oversight. The CCFP is a containment performance measure that provides perspectives on the degree to which the design has achieved a balance between core damage prevention and core damage mitigation. The staff used CCFP in a qualitative manner to confirm that the ESBWR design, combined with the regulatory oversight for identified SSCs, has maintained an acceptable balance between core damage prevention and mitigation. However, it did not use CCFP as a criterion for establishing the availability requirements for nonsafety-related, defense-in-depth systems.

22.3 Specific Steps in the Regulatory Treatment of Nonsafety Systems Process

The staff established the specific steps described below for design certification applicants to implement the process discussed above. Section C.IV.9 of RG 1.206 incorporates these steps.

22.3.1 Comprehensive Baseline Probabilistic Risk Assessment

The RTNSS process starts with a comprehensive Level 3 baseline PRA, which includes all appropriate internal and external events for both power and shutdown operations. The process also includes adequate treatment of R/A uncertainties, long-term safety operation, and containment performance. A margins approach is used to evaluate seismic events. In addressing containment performance, the PRA considers the sensitivities and uncertainties in accident progression, as well as the inclusion of severe accident phenomena, including the explicit treatment of containment bypass. The PRA uses mean values to determine the availability of passive systems and the frequencies of core damage and large releases. The process estimates the magnitude of potential variations in these parameters and identifies significant contributors to these variations using appropriate uncertainty and sensitivity analyses. Finally, the RTNSS process calls for an adverse systems interaction study to be performed and its results to be considered in the PRA. Section 19 of this report discusses the ESBWR baseline PRA, NEDO-33201, Revision 6, "ESBWR Probabilistic Risk Assessment," (ESBWR PRA), issued October 2010.

22.3.2 Search for Adverse Systems Interactions

The RTNSS process includes the systematic evaluation of adverse interactions between the active and passive systems. The results of this analysis are used to initiate design improvements to minimize adverse systems interactions and are considered in developing PRA models, as noted above.

22.3.3 Focused Probabilistic Risk Assessment

The focused PRA for the ESBWR design is a sensitivity study performed on the baseline ESBWR PRA that credits the passive systems and only those active systems necessary to meet the safety goal guidelines approved by the Commission in SECY-94-084 (see Criterion 3 in Section 22.2 of this report). The focused ESBWR PRA results are used in several ways to determine the R/A missions of nonsafety-related, risk-significant SSCs.

First, the focused PRA maintains the same scope of initiating events and their frequencies as that identified in the baseline ESBWR PRA. As a result, nonsafety-related SSCs used to prevent the occurrence of initiating events will be subject to regulatory oversight commensurate with their R/A missions.

Second, following an initiating event, the event tree logic of the comprehensive, Level 3 focused PRA will not include the effects of nonsafety-related standby SSCs. This will allow the combined license (COL) applicant to determine whether the passive safety systems, when challenged, can provide sufficient capability (without nonsafety-related backup) to meet the NRC safety goal guidelines for a CDF of less than 1×10^{-4} per reactor year and for an LRF of less than 1×10^{-6} per reactor year. The design certification applicant will also evaluate the containment performance, including bypass, during a severe accident. If the design certification applicant determines that nonsafety-related SSCs must be added to the focused PRA model to meet the safety goals, these SSCs will be subject to regulatory oversight based on their risk significance.

22.3.4 Selection of Important Nonsafety-Related Systems

The RTNSS process includes the identification of any combination of nonsafety-related SSCs that are necessary to meet NRC regulations, safety goal guidelines, and the containment performance goal objectives. These combinations are based on Criteria 1 and 5 in Section 22.2 of this report, for which NRC regulations are the bases for consideration, and Criteria 3 and 4 in Section 22.2 of this report, for which PRA methods are the bases for consideration. To address the long-term safety issue in Criterion 2 of Section 22.2 of this report, the design certification applicant will use PRA insights, sensitivity studies, and deterministic methods to establish the ability of the design to maintain core cooling and containment integrity beyond 72 hours. Nonsafety-related SSCs that are required to meet deterministic regulatory requirements (Criterion 1), resolve the long-term safety and seismic issues (Criterion 2), and prevent significant adverse systems interactions (Criterion 5) are subject to regulatory oversight.

The staff expects regulatory oversight for all nonsafety-related SSCs needed to meet NRC requirements, safety goal guidelines, and containment performance goals, as identified in the focused ESBWR PRA model. Using the focused PRA to determine the nonsafety-related SSCs important to risk involves the following three steps:

1. Determine those nonsafety-related SSCs needed to maintain the initiating event frequencies at the comprehensive baseline ESBWR PRA levels.
2. Add the necessary success paths (i.e., an event sequence in the PRA event tree that results in no core damage) with nonsafety-related systems and functions to the focused PRA to meet safety goal guidelines, containment performance goal objectives, and NRC regulations. Choose the systems by considering the factors for optimizing the design effects and benefits.

3. Perform PRA importance studies to assist in determining the importance of these SSCs.

22.3.5 Nonsafety-Related System Reliability/Availability Missions

Upon completion of the selection steps described in Section 22.3.4 of this report, the design certification applicant should determine and document the functional R/A missions of those active systems needed to meet safety goal guidelines, containment performance goals, and NRC performance requirements. The design certification applicant should also propose regulatory oversights as discussed in Section 22.3.6 of this report. The design certification applicant should repeat the steps described in Sections 22.3.4 and 22.3.6 of this report to ensure that it selects the most appropriate active systems and associated R/A missions. As part of this process, the design certification applicant should establish graded safety classifications and graded requirements for systems subject to RTNSS based on the importance to safety of the functional R/A missions.

22.3.6 Regulatory Oversight Evaluation

Upon completing the steps detailed in the previous five sections, the design certification applicant should conduct the following activities to determine the means of appropriate regulatory oversight for the RTNSS-important systems:

- Review the information in DCD Tier 2, Revision 9; the ESBWR PRA; and plant performance calculations to determine whether the design of the risk-significant, nonsafety-related SSCs satisfies the performance capabilities and R/A missions.
- Review the information in DCD Tier 2, Revision 9, to determine whether it includes the proper design information for the reliability assurance program, including the design information necessary for compliance with 10 CFR 50.65, which is referred to as the Maintenance Rule.
- Review the information in DCD Tier 2, Revision 9, to determine whether it includes proper short-term availability control (AC) mechanisms if required for safety and as determined by risk significance.

22.4 Other Issues Related to Regulatory Treatment of Nonsafety Systems Resolution

SECY-94-084 discussed several other issues related to overall passive plant performance or the performance of specific passive safety systems. The staff tied resolution of these issues to an acceptable resolution of the RTNSS issue. On the basis of the availability of short-term administrative controls for defense-in-depth equipment, as discussed in Section 22.5.9 of this report, the staff was able to reach acceptable conclusions regarding the ESBWR design related to (1) safe-shutdown requirements as discussed in Section 6.3.1.3 of this report, (2) SBO as discussed in Sections 8.4.2 and 15.5.5 of this report, and (3) General Design Criterion (GDC) 17, "Electric power systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," which addresses ac offsite power sources, as discussed in Section 8 of this report.

22.5 NRC Review of the Applicant's Evaluation of Systems for Inclusion in the Regulatory Treatment of Nonsafety Systems Process

DCD Tier 2, Revision 9, Section 19A, describes the applicant's implementation of the RTNSS process for the ESBWR. The applicant used this process to determine which nonsafety-related systems in the ESBWR should be subject to regulatory treatment and under what conditions that treatment should apply. The implementation of the RTNSS process for the ESBWR followed the scope, criteria, and specific steps described in SECY-94-084 and SECY-95-132, which are discussed in Sections 22.2 and 22.3 of this report. The applicant based the criteria used to determine which systems required regulatory oversight on PRAs of passive system performance (i.e., it used focused PRAs) and a study of initiating event frequency. In addition, the applicant evaluated containment performance challenges; seismic considerations; deterministic assessments of the design's response to events, such as anticipated transients without scram (ATWS) and station blackout (SBO); long-term safety (beyond 72 hours); and adverse systems interactions.

22.5.1 Focused Probabilistic Risk Assessment

As discussed above, one of the steps in the RTNSS process is the use of focused PRA results to identify nonsafety systems needed to meet the CDF and LRF safety goal guidelines. Section 11 of the ESBWR PRA report (NEDO-33201) provides the detailed results of the focused PRAs. Section 19.1.6.1 of this report summarizes the staff's evaluation of the focused PRA results.

22.5.1.1 *Summary of Technical Information*

22.5.1.1.1 Probabilistic Risk Assessment Event Mitigation Evaluation

Chapter 11 of NEDO-33201 describes the focused PRA sensitivity studies performed by the applicant to quantify the importance of nonsafety-related systems in mitigating events. The focused PRA sensitivity studies calculate the CDF and LRF without reliance on nonsafety-related SSC mitigation. If the focused PRA sensitivity studies rely on a nonsafety-related SSC mitigation function to ensure that the calculated CDF and LRF meet the safety goal guidelines, this function is designated as risk important and will be subject to regulatory oversight. The focused PRA sensitivity studies include an evaluation of internal and external events that occur at power and during shutdown operation.

The focused PRA sensitivity studies modify the ESBWR baseline PRA by setting the failure probability of each nonsafety SSC to one. The initiating event frequencies remain the same as in the baseline ESBWR PRA. The failure of the nonsafety and RTNSS systems significantly impacts the Level 1 PRA model CDF. Sections 11.3.3, 11.3.4, and 11.3.5 of the ESBWR PRA list the nonsafety systems considered in the focused PRA sensitivity studies. A series of additional studies were conducted to evaluate the impact of crediting individual nonsafety systems. These sensitivity studies showed that the impact on CDF is significantly reduced with the availability of the diverse protection system (DPS). The unavailability of the DPS, coupled with general transient initiator and common-cause failures of safety-related distributed control and information system (DCIS) software or reactor protection system (RPS) failures, are dominant contributors to CDF.

The CDF and LRF goals will be met with the addition of portions of the DPS that provide the capability to initiate several safety functions. These features include initiating GDSCS injection,

initiating ADS actuation, opening isolation condenser/passive containment cooling system (IC/PCCS) pool cross-connect valves, and closing RWCS/SDC isolation valves. The DPS functions are needed to counter the effects of a dominant risk contribution because of common-cause failures of actuation instrumentation and controls. The DPS has displays and control and actuation functions that are independent from those of the safety-related protection system and engineered safety feature (ESF) functions. They are not subject to the same common-mode/common-cause failures as the safety-related protection system components.

In addition, the DPS provides the following backup functions that are modeled in the ESBWR PRA:

- Scram
- Main steam isolation valve (MSIV) closure
- Safety/relief valve (SRV) actuation
- Fine motion control rod drive (FMCRD) actuation
- ICS actuation
- Standby liquid control (SLC) actuation for loss-of-coolant accident (LOCA)

These functions are not highly risk significant; therefore, the proposed regulatory oversight for these functions is treatment in the Availability Controls Manual (ACM). The ACM contains operational requirements to assure that the actual availability of selected SSCs is commensurate with the assumptions in the risk assessment and with the results of applying the RTNSS process. The NRC reviewed and approves the ACM.

Portions of the nonsafety digital instrumentation and controls system (N-DCIS) support the DPS functions. Consequently, the scope of the RTNSS program also includes the N-DCIS.

Tables 11.3-20 through 11.3-39 of NEDO-33201 compare the results for the baseline PRA, focused PRA sensitivity studies, and RTNSS sensitivity studies. Table 19A-2 in DCD Tier 2, Revision 9, lists the nonsafety-related systems and functions credited in the RTNSS sensitivity study. The RTNSS sensitivity study credits safety systems and systems covered by RTNSS; the focused PRA sensitivity study credits only safety systems.

Since portions of the DPS are credited to meet the CDF and LRF safety goals, these functions are identified as RTNSS important and subject to regulatory oversight. In accordance with 10 CFR 50.36(c)(2)(ii)(D), Criterion 4, the plant's TS must establish limiting conditions of operation (LCOs) for an SSC that either operating experience or the PRA has shown to be significant to public health and safety. Therefore, as described in DCD Tier 2, Revision 9, Section 16.0, the availability of these functions is enforced through the TS.

22.5.1.1.2 Uncertainty Evaluation

DCD Tier 2, Revision 9, Section 19A.4.2, considers potential uncertainties associated with assumptions made in the ESBWR PRA models of passive systems (e.g., failure rates of GDCS injection line check and squib valves). This PRA uncertainty evaluation determines which nonsafety-related SSCs should be included in the scope of the RTNSS program to add margin to compensate for the uncertainties in the ESBWR PRA. As a result of this evaluation, the low-pressure core injection capability of the FAPCS, including support systems for that system, was designated as RTNSS to add margin to compensate for potential uncertainties. Two injection trains provide this function of the FAPCS. These injection trains are physically and electrically separated such that no single active component failure can fail the function. Supporting

systems for the FAPCS include the RCCWS, standby diesel generators (SDGs), plant investment protection (PIP) buses, electrical building HVAC, fuel building HVAC, turbine building HVAC, reactor building HVAC, the nuclear island chilled water system (NICWS), and the PSWS.

22.5.1.1.3 Probabilistic Risk Assessment Initiating Event Frequency Evaluation

DCD Tier 2, Revision 9, Section 19A.4.3, describes the applicant's evaluation of the importance of the nonsafety-related systems to the initiating event frequencies used for at-power and shutdown initiating event frequencies in the ESBWR PRA. The applicant identified eight categories of initiating events for at-power and shutdown conditions.

The at-power initiating event categories include the following:

- Generic transients
- Inadvertent opening of a relief valve
- Transient with a loss of feedwater
- Loss of preferred power
- LOCA

The shutdown initiating event categories include the following:

- Shutdown loss of decay heat removal
- Shutdown loss of offsite power
- Shutdown LOCA

The evaluation of the importance of the unavailability of nonsafety-related SSCs to the initiating event frequencies is based on the following three screening criteria:

1. Does the calculation of the initiating event frequency consider the nonsafety-related SSCs?
2. Does the unavailability of the nonsafety-related SSCs significantly affect the calculation of the initiating event frequency?
3. Does the initiating event significantly affect the CDF and the LRF?

In DCD Tier 2, Revision 9, Section 19A.4.3, the applicant stated that only safety-related systems are involved in the initiation of a stuck-open relief valve event and LOCA events inside containment. Therefore, in accordance with Criterion 1 of this section, RTNSS for nonsafety-related systems associated with these initiating events does not apply.

In the case of generic transients, the initiating event frequency is an assumed bounding value based on operating experience and does not depend on the availability or reliability of any nonsafety SSCs. Consequently, in accordance with Criterion 2 of this section, no nonsafety-related systems associated with these initiating events are candidates for regulatory treatment.

In DCD Tier 2, Revision 9, Section 19A.4.3, the applicant stated that the dominant risk contributions in the loss of preferred power event category are from the loss of incoming ac power from the utility grid and weather-related faults. These faults result from the failure of components that are not controlled by the site organization. Nonsafety-related SSCs controlled by the site organization, such as substations, breakers, motor control centers, and protective

relays, do not significantly affect the initiating event frequency. In addition, the applicant noted that a nonsafety-related emergency ac power system designed to mitigate the effects of a loss of preferred power (i.e., the SDGs and PIP buses) has RTNSS controls based on other criteria.

The loss of feedwater event is caused by failures in nonsafety-related components in the condensate and feedwater system, but is not a significant contributor to CDF. The first two screening criteria are met. The third screening criterion is not met because the ESBWR has improved design features that affect the operation of these systems to increase reliability and reduce initiating event frequency. The design improvements include several features in the advanced design of the new generation feedwater level control system, which adds significant reliability that leads to a lower probability of loss of feedwater initiating events. The feedwater level control system is implemented on a triplicate, fault-tolerant digital controller. Therefore, a control failure is much less likely to occur in the ESBWR than in the design of the current generation of reactors. Because of these improvements in the feedwater controller design, the dominant contributors to a total loss of feedwater are a loss of control power to the feedwater controllers and loss of ac power to the pumps.

Initiating events considered for shutdown modes of operation (i.e., Modes 5 and 6) include LOCA, loss of preferred power, and loss of decay heat removal. The applicant concluded that the unavailability of nonsafety-related systems did not affect the loss of preferred power initiating event for reasons similar to those given for the at-power version of this event. Loss of preferred power due to plant-centered and switchyard-related faults were not considered candidates because plant-centered and switchyard-related component failures are not risk significant; therefore the third screening criterion is not met. The nonsafety-related RWCU/SDC removes decay heat in Modes 5 and 6; therefore, failures in this system may affect the loss of decay heat removal initiating event frequency. However, RWCU component failures leading to loss of shutdown cooling do not meet the threshold for significance, and therefore, the third screening criterion is not met.

22.5.1.2 Regulatory Criteria

The NRC does not have any specific regulatory requirements governing the application of the focused PRA for determining nonsafety systems requiring regulatory treatment. SECY-94-084, SECY-95-132, and the Commission's SRM on SECY-94-084 discuss guidelines for applying the focused PRA in the RTNSS process. SRP Section 19.0, Revision 2, of NUREG-0800, which addresses use of the focused PRA in the RTNSS process in a manner acceptable to the NRC, references these documents.

22.5.1.3 Staff Evaluation

22.5.1.3.1 Probabilistic Risk Assessment Event Mitigation Evaluation

The applicant has performed a focused PRA and applied it in a manner consistent with NRC guidance. Using this process, the applicant determined that NRC safety goals could not be met when the focused ESBWR PRA credited only safety-related systems. It identified risk-significant functions of the nonsafety-related DPS with mitigation capability sufficient to reduce the CDF and LRF below the NRC safety goals when credited in the focused PRA. The applicant has included requirements for the availability of these nonsafety-related functions through the TS, in accordance with 10 CFR 50.36(c)(2)(ii)(D), as discussed in Section 22.5.8 of this report.

22.5.1.3.2 Uncertainty Evaluation

The applicant has identified the FAPCS and its support equipment as nonsafety-related SSCs requiring regulatory treatment to compensate for the uncertainty associated with assumptions made in the PRA models of passive systems (as discussed in DCD Tier 2, Revision 9, Section 19A.4.2). The FAPCS provides a diverse backup for the passive GDCCS core injection function and passive PCCS containment heat removal function and therefore directly addresses uncertainty in the ability of passive systems to perform as designed. For this reason, the staff finds the applicant's treatment of uncertainty in the RTNSS evaluation acceptable.

22.5.1.3.3 Probabilistic Risk Assessment Initiating Event Frequency Evaluation

The nonsafety-related systems that impact the loss of feedwater initiating event are required to continuously operate to support normal plant power operation. By providing more fault-tolerant system designs that increase plant reliability and availability, these improvements directly increase plant safety by reducing the potential for plant transients or trips that could challenge the plant's normal operation. Because the regulatory oversight of the RTNSS-important nonsafety-related SSCs is intended to ensure the reliability and availability of those systems that are normally in standby operation, it is not meaningful to consider additional regulatory oversight beyond the existing operational controls for the nonsafety-related systems that are required to operate during power operation. The staff agrees with the applicant that additional regulatory oversight for the ESBWR nonsafety-related SSCs that impact the initiating event, beyond that provided by operational controls, will not provide significant benefit in reducing the initiating event frequency, the CDF, or the LRF. In addition, the staff notes that SSCs that can cause a loss of feedwater initiating event are covered under the scope of the Commission's requirements for monitoring the effectiveness of maintenance under the Maintenance Rule because such an event could result in a reactor scram or actuation of a safety-related system. Consequently, the staff agrees that no additional oversight is needed.

The staff finds the applicant's assessment of LOCA and loss of preferred power initiating events for both at-power and shutdown conditions to be acceptable. The applicant's assessment of the shutdown decay heat removal initiating event is based on the assumption that both pumps in the RWCUSDC will be running in Modes 5 and 6. Section 19.1.6 of this report (see discussion of Request for Additional Information [RAI] 19.1-4) discusses the staff evaluation of this assumption.

22.5.1.4 Conclusions

Based on the above evaluation, the staff concludes that the applicant's process for using the focused PRA results to identify RTNSS-important nonsafety-related SSCs follows the process approved by the NRC and is therefore acceptable.

22.5.2 Containment Performance Consideration

22.5.2.1 Summary of Technical Information

DCD Tier 2, Revision 9, Section 19.2, assesses the ESBWR design for meeting the following deterministic containment performance goal described in SECY-93-087 and approved by the Commission in an SRM dated July 21, 1993:

The containment should maintain its role as a reliable, leak-tight barrier by ensuring that containment stresses do not exceed ASME service level C limits for a minimum period of 24 hours following the onset of core damage, and that following this 24-hour period the containment should continue to provide a barrier against the uncontrolled release of fission products.

The applicant has not identified any nonsafety-related SSCs that are relied upon to meet this performance goal. The applicant has also assessed compliance of the ESBWR design with the probabilistic containment performance goal of 0.1 CCFP with and without credit for nonsafety-related SSCs. Chapter 11 of NEDO-33201 describes these studies, performed with the focused Level 2 ESBWR PRA. The applicant asserted that the NRC goals of less than 1×10^{-4} per year for CDF and less than 1×10^{-6} per year for LRF can be met by crediting the DPS. No additional systems are required to meet the containment performance goal.

The basemat-internal melt arrest and coolability (BiMAC) device provides an engineered method to ensure heat transfer between a core debris bed and cooling water in the lower drywell during severe accident scenarios. The BiMAC device is not safety-related. It is included in the ESBWR design to reduce the uncertainties involved with severe accident phenomenology. Thus, the scope for RTNSS includes the BiMAC device, the nonsafety-related GDSC deluge squib valves, and the associated actuation logic.

Igniters (glow plugs) in the lower drums of the PCCS condensers recombine the hydrogen and oxygen at low concentrations, thereby keeping the resultant internal pressure of the PCCS condensers within acceptable limits to ensure there is no plastic deformation during a detonation under severe accident conditions. The igniters are activated by the existing GDSC deluges (BiMAC) control system implemented in a nonsafety-related technology programmable logic controller. Like the BiMAC device, the ignitors are a nonsafety-related feature that helps protect the containment during severe core damage accidents and reduce the uncertainties involved with severe accident phenomenology. As such, the ignitors have been included in the scope of RTNSS.

The applicant has addressed the potential for steam bypass of the suppression pool and potential failure of the PCCS heat exchanger tubes in the design of the ESBWR. The applicant has not identified any nonsafety-related SSCs that are relied upon to address these issues. DCD Tier 2, Revision 9, Section 6.2.1.1.5, addresses steam bypass of the suppression pool. DCD Tier 2, Revision 9, Section 6.2.2.3, discusses the design of the PCCS heat exchanger tubes.

22.5.2.2 Regulatory Criteria

The objective of the assessment is to identify any nonsafety-related SSC functions needed to meet the containment performance goals, including those related to containment bypass during severe accidents. The containment bypass issue from SECY-93-087, Issue II.G, is concerned with potential sources of steam bypassing the suppression pool and failure of heat exchanger tubes in the PCCS.

For the ESBWR, the probabilistic criterion for assessing containment performance is the degree to which the design comports with the Commission's probabilistic containment performance goal of 0.1 CCFP when no credit is provided for the performance of the nonsafety-related, defense-in-depth systems for which there will be no regulatory oversight. SECY-93-087 discusses the following deterministic criterion:

The containment should maintain its role as a reliable, leak-tight barrier by ensuring that containment stresses do not exceed ASME service level C limits for a minimum period of 24 hours following the onset of core damage, and that following this 24-hour period the containment should continue to provide a barrier against the uncontrolled release of fission products.

22.5.2.3 Staff Evaluation

Section 19.1.4.2 of this report presents the staff's evaluation of the applicant's deterministic containment performance assessment.

Section 6.2 of this report discusses the staff's review of the PCCS heat exchanger tube design and those design features incorporated to address potential suppression pool bypass.

The debris bed cooling function of the BiMAC device and the igniters (glow plugs) in the lower drums of the PCCS condensers provide defense-in-depth protection against containment failure, thereby addressing uncertainty in the ability of passive systems to perform as designed. The staff finds that inclusion of the BiMAC device, its support systems, and the igniters in the scope of RTNSS under Criterion 4 is appropriate.

22.5.2.4 Conclusions

The staff finds the applicant's selection of SSCs under this RTNSS selection criterion to be acceptable.

22.5.3 Seismic Consideration

22.5.3.1 Summary of Technical Information

In DCD Tier 2, Revision 9, Section 19A.3.2, the applicant stated that the seismic margins analysis (SMA) described in Section 19.1.5.1 of this report assesses the seismic ruggedness of safety-related plant systems and the nonsafety systems required for long-term safety (beyond 72 hours). Based on this analysis, the applicant indicated that no accident sequence leading to core damage has a high confidence of low probability of failure (HCLPF) value less than 1.67 times the peak ground acceleration of the safe-shutdown earthquake (SSE); the design certification refers to the SSE as the certified seismic design response spectra (CSDRS). Therefore, the applicant identified no additional nonsafety-related SSCs as RTNSS candidates because of seismic events.

22.5.3.2 Regulatory Criteria

The NRC policy associated with RTNSS, as delineated in SECY-94-084, states that SSC functions relied upon to resolve long-term safety (beyond 72 hours) issues and to address seismic events are candidates for consideration for regulatory oversight. SECY-94-084 also states that seismic events can be evaluated by a margins approach.

22.5.3.3 Staff Evaluation

The staff reviewed DCD Tier 2, Revision 6, Sections 19A.3.2 and 19.2.3.2.4, which referred to Section 15 of NEDO-33201, Revision 4, and described the SMA. In RAI 22.5-8, the staff asked

the applicant to discuss the following issues to gain a clear understanding of the details of the SMA in relation to the RTNSS components:

- The basis for the assertion that RTNSS SSCs designed to the requirements of the 2003 International Building Code (IBC) (also referred to as IBC-2003) will satisfy the minimum HCLPF value of 1.67 times the SSE
- The technical basis for applying generic fragility and capacity data in judging the seismic ruggedness of the systems that qualify for RTNSS
- The available ESBWR-specific component test-based or design-experience-based seismic capacity data that would further support the validity of the seismic capacity, fragility, and HCLPF values obtained in the SMA

In response, the applicant stated the following:

- The minimum HCLPF value has been revised to 0.84g ($1.67 \times 0.5g$). As shown in ESBWR DCD Tier 2, Revision 4, Table 19.2-4, only safety-related SSCs and RTNSS Criterion B1 components, which are designed as seismic Category II, are included in the SMA and, therefore, are expected to be seismically rugged. The SMA does not credit any RTNSS Criterion B2 components, which are designed to the IBC-2003 provisions.
- Component fragilities have been revised and moved from Table 15-1 to Table 15-7 in NEDO-33201, Revision 5, "ESBWR Probabilistic Risk Assessment." The only RTNSS component included in the SMA is the diesel-driven pump for the fire protection system (FPS), which is designed to seismic Category I requirements in accordance with ESBWR DCD Tier 2, Revision 4, Section 19A.4.2.4, and its fragility is therefore achievable.
- The SMA approach is a qualitative process. However, safety-related equipment is also seismically qualified in a process that is test-based following the Institute of Electrical and Electronics Engineers (IEEE) Std 323, "Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," issued September 2003, and IEEE Std 344, Revision 4, "Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," issued December 2004. The qualification process in these standards is a stable process for which high confidence is afforded the qualified equipment and the ability to meet the seismic margin is achievable in practice.

The staff observed that, in DCD Tier 2, Revision 4, Table 19.2-4, the SMA credited only safety-related SSCs in addition to the diesel-driven fire protection pump (RTNSS B1¹). The applicant committed to design RTNSS B1 SSCs as seismic Category II. In DCD Tier 2, Revision 4, Section 19A.4.2.4, the applicant stated that piping and components associated with the connection of the fire protection pump are designed to meet Quality Group C and seismic Category I. Accordingly, all SSCs included in the SMA are designed to withstand the SSE.

¹ The term "RTNSS B" has been defined by the applicant and refers to SSCs that meet selection Criterion 2 in Section 22.2 of this report. The terms "RTNSS B1" and "RTNSS B2" have been defined by the applicant and refer to categories of SSCs that meet RTNSS selection Criterion 2 in Section 22.2 of this report, but receive different regulatory treatment. The diesel-driven fire protection pump falls into the B1 category.

Furthermore, the seismic qualification process, in accordance with IEEE standards, is acceptable to the staff and provides reasonable assurance that the qualified equipment will achieve the seismic margin. On this basis, the staff considers RAI 22.5-8 to be resolved.

The staff has reviewed the SMA described in Section 19.2.3.24 of DCD Tier 2, Revision 9, and confirmed that it credits only safety-related SSCs and the diesel fire pump, which are designed to the seismic Category I standard.

22.5.3.4 Conclusions

The SMA used to perform the seismic assessment of the ESBWR standard plant design credits only safety-related SSCs and the diesel-driven fire protection pump. This pump is designed to seismic Category I requirements. All SSCs relied upon to address a design-basis seismic event are designed to withstand the effects of the SSE, in accordance with the requirements of DCD Tier 2, Revision 9, Section 3.7, which provides reasonable assurance that these SSCs will achieve the stated seismic margin. On this basis, the staff finds the results of the SMA, with regard to RTNSS components, acceptable.

22.5.4 Deterministic Anticipated Transient without Scram and Station Blackout Evaluation

22.5.4.1 Station Blackout Assessment

22.5.4.1.1 Summary of Technical Information

The ESBWR is designed to cope with an SBO event for 72 hours. The analysis in DCD Tier 2, Revision 9, Section 15.5.5, demonstrates that reactor water level is maintained above the top of active fuel by operation of the ICS, which is safety-related. Operation of the PCCS, which is also safety-related, maintains the containment and suppression pool pressures and temperatures within their design limits. Therefore, the integrity of containment is maintained. The ESBWR is designed to successfully mitigate an SBO event to meet the requirements of 10 CFR 50.63 without relying on nonsafety-related systems.

22.5.4.1.2 Regulatory Criteria

The staff policy associated with RTNSS, as delineated in SECY-94-084, states that SSC functions relied upon to meet deterministic NRC performance requirements in 10 CFR 50.63 for mitigating SBO events are candidates for consideration for regulatory oversight.

22.5.4.1.3 Staff Evaluation

Section 15.5.5 of this report presents the staff's safety evaluation of the applicant's analysis of the SBO event. Based on this review, the staff finds that the ESBWR can successfully mitigate an SBO event to meet the requirements of 10 CFR 50.63 without relying on nonsafety-related systems.

22.5.4.2 Anticipated Transient without Scram Assessment

22.5.4.2.1 Summary of Technical Information

Under 10 CFR 50.62, boiling-water reactors (BWRs) must have (1) an automatic recirculation pump trip, (2) an alternate rod insertion (ARI) system, and (3) an automatically initiated SLC system for ATWS prevention and mitigation.

Unlike the current BWR fleet, the ESBWR does not use recirculation pumps, so the recirculation pump trip logic does not exist. Instead, the ESBWR uses natural circulation along with automatic feedwater control. Thus, the ESBWR has implemented an automatic feedwater runback (FWRB) feature under conditions indicative of an ATWS event. This provides a reduction in water level, core flow, and reactor power similar to the recirculation pump trip. This feature is judged to be a major contributor to preventing reactor vessel overpressure and possible short-term fuel damage for ATWS events.

The ESBWR has an ARI system with sensors and logic that are diverse and independent of the RPS. The ARI employs hydraulic pressure to scram the plant using the three sets of air header dump valves of the CRD system. The DPS implements the ARI logic.

The ESBWR has the required automatic initiation of the SLC system under conditions indicative of an ATWS. The ATWS/SLC system mitigation logic provides a diverse means of emergency shutdown using the SLC for soluble boron injection. The ESBWR design uses electrical insertion of FMCRDs with sensors and logic that are diverse and independent of the RPS.

A nonsafety system may perform this ATWS diverse automated backup function if the system is of sufficient quality to perform the necessary functions under the associated event conditions, as described in the enclosure to Generic Letter 85-06, "Quality Assurance Guidance for ATWS Equipment That Is Not Safety-Related," dated January 16, 1985. The ATWS mitigating logic system is implemented with the safety-related and nonsafety-related DCIS. The nonsafety-related DPS processes the nonsafety-related portions of the ATWS mitigation logic and is designed to mitigate the effects of potential digital protection system common-cause failures. The DPS transmits the FWRB signal from the ATWS mitigation logic to the feedwater control system (FWCS). The applicant identified the nonsafety-related portions of the ATWS mitigation logic as requiring regulatory treatment in accordance with the RTNSS process.

22.5.4.2.2 Regulatory Criteria

The staff policy associated with RTNSS, as delineated in SECY-94-084, states that SSC functions relied upon to meet deterministic NRC performance requirements under 10 CFR 50.62 for mitigating ATWS are candidates for consideration for regulatory oversight.

22.5.4.2.3 Staff Evaluation

The applicant selected the ARI system, the FWRB logic, and the ATWS initiation controls for the SLC system as RTNSS equipment. As discussed in DCD Tier 2, Revision 9, Sections 6.3.1 and 9.3.5, the SLC system is part of the ESBWR emergency core cooling system (ECCS) and is classified as safety-related. It is only the ATWS/SLC actuation logic that is classified as an RTNSS function. This logic includes the diverse ADS inhibit logic that is required, along with the safety-related ADS inhibit logic, for SLC initiation to be successful. The applicant stated in DCD Tier 2, Revision 9, Section 19A.2.1, that the requirements for these systems and functions are

consistent with those specified in the ATWS rule. Section 7 of this report presents the detailed safety evaluation of the specific physical equipment; logic; detailed design; design acceptance criteria; defense-in-depth attributes; self-testing features; and inspections, tests, analyses, and acceptance criteria (ITAAC) used to satisfy the ATWS rule. Section 15.5.4 of this report presents the staff's safety evaluation of the applicant's analysis of the ATWS event.

22.5.4.2.4 Conclusions

Based on its review, the staff concludes that the applicant has correctly identified the nonsafety equipment relied upon to meet the ATWS rule and therefore requiring regulatory treatment.

22.5.5 Evaluation of Adverse Systems Interactions

22.5.5.1 Summary of Technical Information

DCD Tier 2, Revision 9, Section 19A.6 states that the purpose of the Criterion E analysis is to systematically evaluate adverse interactions between the active and passive systems. Section 19A.6 states that an adverse systems interaction exists if the action or condition of an active, interfacing system causes a loss of safety function of a passive safety-related system. The section further states that a systematic process is used to analyze specific features and actions that are designed to prevent postulated adverse interactions, while taking into consideration the operating experience that has been used in the current design criteria to prevent adverse systems interactions.

During the assessment of potential adverse system interactions, the applicant identified an issue that relates to MCR habitability under certain post-LOCA containment cooling with fuel failure conditions. The potentially adverse interaction involves the need to process the contaminated air expected following fuel damage. The processing of contaminated water occurs within the reactor building. A filtered HVAC system (i.e., the contaminated area ventilation system (CONAVS)) Reactor Building HVAC Accident Exhaust Filter Unit ensures that effluent from the reactor building is controlled so that dose levels in the MCR remain within acceptable limits. Contaminated air from the reactor building must be processed following fuel damage. DCD Tier 2, Revision 5, Section 5.4.8, described post-LOCA cooling with fuel failure, during which time a CONAVS Reactor Building HVAC Accident Exhaust Filter Unit may operate to prevent exceedance of the MCR dose limits. If the CONAVS filters do not perform with adequate efficiency, the theoretical control room doses may be exceeded for certain design-basis LOCAs. Therefore, it is prudent to place increased regulatory treatment on these filters as an added measure to ensure acceptable performance.

The lower drywell provides an equipment hatch for removal of equipment during maintenance and an air lock for personnel entry. These access openings are sealed during normal operation, but may be opened when the plant is shut down. Closure of both hatches is required to maintain water level during makeup following a shutdown-LOCA that occurs in either Mode 5 or Mode 6. Open hatches would inhibit the safety-related makeup systems from performing their intended function. Therefore, the lower drywell hatches are in the scope of RTNSS.

22.5.5.2 Regulatory Criteria

The staff presented criteria for the evaluation of nonsafety-related SSCs in SECY-94-084. The SECY paper indicates that the functions of SSCs relied upon to prevent significant adverse system interactions should be considered candidates for regulatory oversight. The staff used

the guidance in the SECY paper and associated SRM as the basis for its review of the applicant's evaluation of adverse system interactions in the ESBWR.

22.5.5.3 Staff Evaluation

The staff reviewed the description of the evaluation of adverse systems interactions provided in DCD Tier 2, Revision 4, using the Commission guidance in SECY-94-084. The staff considered the specific SSCs included in the scope of RTNSS under this criterion and the applicant's rationale for their inclusion.

In RAI 22.5-17, the staff requested that GEH provide additional information to explain and clarify the systematic approach used to evaluate adverse system interactions, including the manner in which potential adverse systems interactions are evaluated for nonsafety-related components. In response to RAI 22.5-17, the applicant described the systematic approach used to evaluate adverse system interactions. Passive safety functions are evaluated to identify target areas or components that could be affected by an adverse condition. The systems that interface with each passive safety function are identified to determine whether nonsafety-related SSCs could potentially cause a failure of a passive safety function. Each interface between a nonsafety-related SSC and a passive safety function is evaluated for potential adverse effects. Both functional and spatial interactions are addressed. The development of the fire and flooding portions of the PRA model further addressed spatial interactions. The result of the systematic evaluation is the identification of nonsafety-related SSCs that could cause adverse system interactions. These SSCs should then be considered for additional regulatory oversight. GEH stated that the results of the adverse systems interaction evaluation of the ESBWR did not identify any SSCs that should be considered for the RTNSS program. The staff found the GEH description of the approach used to evaluate adverse system interactions to be acceptable, but GEH did not discuss how potential adverse system interactions for nonsafety-related components from functional or spatial interactions will be identified during the engineering and construction phase of the ESBWR plant. Therefore, RAI 22.5-17 was tracked as an open item in the safety evaluation report (SER) with open items.

In RAI 22.5-17 S01, the staff requested that GEH explain how it will identify and address, during the detailed engineering and construction phase, potential adverse system interactions from functional or spatial interactions for nonsafety-related components to ensure that the functions of safety-related and RTNSS systems will not be adversely impacted. In response to RAI 22.5-17 S01, GEH stated that it performs an adverse system interactions evaluation for any changes to the ESBWR design. Design phase engineering procedures that are part of the GEH quality program address the effects of fire, flood, pipe break, missile hazard, and seismic events in terms of the potential for adverse interaction given the presence of two or more systems in proximate locations. The design input procedure contains provisions for identifying design inputs during development or modification of the design of systems such as consideration of loads (e.g., seismic, wind, thermal, and dynamic); environmental impact (e.g., temperature, humidity, radiation, and electromagnetic radiation); failure effects; and reliability requirements (including interactions that could impair important functions). The staff considers this response to be acceptable in clarifying the consideration of potential system interactions. Therefore, RAI 22.5-17 and the associated open item are resolved.

Safety-related systems are required to be protected from the effects of failures in the safety-related and nonsafety-related systems. DCD Tier 2, Revision 4, addresses those interactions in Section 3.3, Section 3.4, Section 3.5, Section 3.6, and Section 3.7. In response to RAI 22.5-5, GEH described features to be implemented during the engineering and construction phase to

ensure that RTNSS systems are not adversely affected by interactions with internal flooding, external flooding, missiles generated during seismic events and high winds, and piping failures in fluid systems outside containment. GEH incorporated Tables 19A-3 and 19A-4 into DCD Tier 2, Revision 5, Section 19A to clarify the consideration of potential adverse interactions.

In addition to evaluating system interactions as part of the ESBWR design certification, COL applicants must submit a quality program for the design of their proposed ESBWR plant. In particular, DCD Tier 2, Revision 9, Section 17.2 includes COL information items that require the COL applicant to describe the quality assurance program for the construction and operations phases, as well as the quality assurance program for design activities that are necessary to adapt the certified standard plant design to a specific plant implementation. This will reduce the potential to introduce system interactions during the transition from the certified design to the plant-specific implementation.

The applicant identified the Reactor Building HVAC Accident Exhaust Filter Units and the lower drywell hatches for treatment under RTNSS and demonstrated that these SSCs need to function successfully to ensure that safety-related systems perform their intended functions. The applicant has included ACs for these SSCs in the ACM. The staff finds this treatment to be appropriate and acceptable.

Based on the information provided by GEH, including the COL information items, the staff finds that the applicant's consideration of potential system interactions for RTNSS systems satisfies the applicable Commission guidance for review of the ESBWR design certification.

22.5.6 Post-72-Hour Actions and Equipment

22.5.6.1 *Summary of Technical Information*

The ESBWR is designed so that passive systems are able to perform all safety functions for 72 hours after an initiating event without the need for active systems or operator actions. After 72 hours, nonsafety-related systems can be used to replenish the passive systems or to perform safety and postaccident recovery functions directly. In DCD Tier 2, Revision 9, Section 19.A.3.1, the applicant described the actions and equipment needed in the post-72-hour period for the ESBWR. This section of the DCD, states that the following safety functions are relied upon in the 72-hour period following an accident:

- Containment integrity
- Core cooling
- Control room habitability
- Postaccident monitoring

Section 19.A.3.1 describes the nonsafety-related equipment that is relied upon to ensure that these safety functions are successful in the post-72-hour period. The staff's regulatory criteria and evaluation of this information against those criteria are provided below.

22.5.6.2 *Regulatory Criteria*

The staff's evaluation of post-72-hour actions appears in SECY-96-128, "Policy and Key Technical Issues Pertaining to the Westinghouse AP600 Standardized Passive Reactor Design," dated June 12, 1996, which the Commission approved in a memorandum dated January 15, 1997. In SECY-96-128, the staff took the position that post-72-hour actions related

to all design-basis events must be accomplished with onsite equipment and supplies in the time-frame beyond 72 hours after a design-basis event occurs. After 7 days, replenishment of consumables, such as diesel fuel oil from offsite suppliers, can be credited. The staff further stated that the equipment needed for post-72-hour support need not be in “automatic standby mode,” but must be readily available for connection and protected from natural phenomena, including seismic events, as required by GDC 2, “Design bases for protection against natural phenomena.” In a memorandum to the Commission dated June 23, 1997, the staff outlined the implementation of the staff position in SECY-96-128. The staff stated that, to ensure that post-72-hour SSCs can withstand the effects of an SSE without the loss of capability to perform their required functions, the SSCs should be analyzed, designed, and constructed using the method and criteria for seismic Category II building structures. The staff also stated that a COL applicant would be required to have appropriate ACs, consistent with RTNSS requirements, for nonsafety-related SSCs for post-72-hour support.

22.5.6.3 Staff Evaluation

22.5.6.3.1 Augmented Design Standards

In DCD Tier 2, Revision 9, Section 19A.3.1, the applicant stated that RTNSS B SSCs have redundant active components. These SSCs are designed to appropriate seismic design standards and are protected from high winds and flooding hazards. In addition, these SSCs are subject to harsh environmental conditions and are able to perform in such conditions.

In DCD Tier 2, Revision 9, Section 19A.8.3, the applicant described the augmented design standards used in the design of RTNSS systems that meet Criterion B (See footnote in Section 22.5.33 of this report). The applicant reiterated that Criterion B components are required to function following a seismic event and that they are designed to seismic Category II criteria, at a minimum. In addition, any non-RTNSS systems that can adversely interact with RTNSS B systems are designed to the same seismic requirements as the affected RTNSS system. The applicant also stated that Criterion B systems must meet design standards to withstand winds and missiles generated from Category 5 hurricanes. With regard to flood protection, the applicant stated that the plant design considers the relevant requirements of GDC 2, and meets the guidelines of RG 1.59, Revision 1, “Design-Basis Floods for Nuclear Power Plants,” issued August 1977, and RG 1.102, Revision 1, “Flood Protection for Nuclear Power Plants,” issued September 1976. RG 1.59 provides guidance for establishing flood design criteria. RG 1.102 provides guidance for establishing the means for protection of safety-related SSCs against flood. In addition, the applicant stated that, to ensure that RTNSS systems are protected from flood-related effects associated with fluid piping and component failures, they are located above the maximum internal flooding level discussed in DCD Tier 2, Revision 9, Section 3.4.

The staff reviewed the augmented design standards described in DCD Tier 2, Revision 9, Section 19A.8.3. The staff finds that, at a minimum, RTNSS SSCs meeting Criterion B are designed in accordance with seismic Category II requirements. This provides reasonable assurance that these SSCs can perform their function following a seismic event. Therefore, the staff finds these standards acceptable.

In RAI 22.5-6, the staff asked the applicant to confirm that the ESBWR design does not contain nonsafety-related structures that either support or surround the RTNSS systems whose failure may negatively affect the RTNSS system functions. RAI 22.5-6 was being tracked as an open item in the SER with open items.

In response to RAI 22.5-6, the applicant stated that the structures that house the systems and components that meet RTNSS Criteria B1 and B2 are required to meet the augmented standards presented in DCD Tier 2, Revision 4, Section 19A.8.3. The applicant also provided a table showing the structures that house RTNSS components for criteria other than B and indicated that the minimum structural design classification for those structures is seismic Category II.

During its review of the response, the staff noted that some of the structures that house components that meet RTNSS Criteria B2 are designed to the standards of IBC-2003. The seismic provisions of these standards use a 2,500-year event as the maximum considered earthquake. This ground motion is then reduced by a factor of two-thirds to produce the design ground motion. Such ground motion may have a return period varying from approximately 500 to 1,500 years, depending on the regional seismicity. The design seismic demands are further modified (generally reduced) in the design calculations to account for earthquake energy absorption through nonlinear behavior (i.e., component cracking and yielding). Structures classified as IBC-2003 Occupancy Category IV are designed as Seismic Use Group III and are expected to achieve the immediate occupancy performance level at the design-level ground motion. Based on the provisions documented in Federal Emergency Management Agency (FEMA) 450, "2003 NEHRP Recommended Provisions for Seismic Regulations of New Buildings and Other Structures," issued June 2004, which forms the technical bases for the IBC-2003 seismic provisions, "immediate occupancy" is a performance level below an operational or a functional level. FEMA 450 further states that, at the immediate occupancy level, damage to the structural systems is very slight and the structure remains safe to occupy; however, some repair is probably required before the structure can be restored to normal service. Equipment housed in such structures, on the other hand, is expected to experience more damage. In particular, utilities necessary for the normal function of systems are not expected to be available. In addition, some equipment and systems may experience internal damage because of the shaking of the structure. Ultimately, minor structural repairs are required; however, significant nonstructural repair and cleanup are probably required before normal function of the structure can be restored. In light of this, the staff was concerned that the IBC-2003 seismic provisions may not be adequate to ensure that the post-72 hour systems, structures and components can withstand the effects of a (SSE) without the loss of capability to perform their required functions. Based on its understanding of the limitations of the IBC-2003 seismic provisions, the staff requested the following information in RAI 22.5-6 S01 to obtain an explanation of the applicant's approach to compensate for the limitations of the IBC-2003 provisions:

1. Identify in the DCD all nonsafety-related, nonseismic structures that house or support RTNSS systems meeting Criteria B1 and B2.
2. Provide the technical rationale to support the assertion that IBC-2003 seismic provisions will achieve functional performance under SSE conditions.
3. Given the lower hazard and performance levels of the IBC-2003 as compared to the SSE hazard with a functional performance level, explain how the availability and reliability of RTNSS Criterion B2 systems and their surrounding or supporting structures will be ensured.
4. In the event of an SSE, explain in the DCD how RTNSS Criteria B1 and B2 systems are protected against adverse interaction resulting from the failure of adjacent nonsafety-related, nonseismic structural and nonstructural components that are designed to the IBC-2003 seismic provisions.

In response to RAI 22.5-6 S01, the applicant provided a complete list of RTNSS Criterion B2 systems located in nonsafety-related, nonseismic structures. The applicant stated that the IBC-2003 seismic provisions use a 2-percent exceedance value as the maximum considered earthquake ground motion that would result in acceptable safety for most regions of the United States. However, ESBWR RTNSS SSCs are designed to SSE ground motion. When RTNSS systems are located in non-Category I structures, these structures, although categorized as nonseismic, are seismically designed using IBC-2003 to maintain structural integrity with a margin of safety equal to a seismic Category I structure under SSE conditions. A dynamic analysis method is used with the SSE ground motion input equal to two-thirds of the ESBWR CSDRS.

The applicant also identified the following additional criteria that are used for the design of RTNSS systems:

1. Importance factor of 1.5 that cancels the two-thirds reduction factor in response spectra
2. Seismic Category D/Seismic Use Group III
3. Response modification factor, $R=2$, which results in seismic loads 3 times larger than required by IBC-2003
4. Loads, load combinations, and performance criteria consistent with IBC-2003

RTNSS Criterion B1 equipment is qualified to IEEE Std 344-1987 to demonstrate seismic performance. The SMA does not credit RTNSS Criterion B2 components. RTNSS Criterion B2 equipment is qualified to IEEE Std 344-1987 to demonstrate structural integrity.

Subsequently, the applicant recategorized the SSCs in scope for RTNSS to address long-term safety and seismic requirements as Criterion B, thus eliminating the Criterion B1 and Criterion B2 grouping. All RTNSS Criterion B SSCs meet seismic Category II design requirements; this eliminates the need to use IBC-2003 seismic provisions for the design of RTNSS SSCs meeting Criterion B2. Non-RTNSS systems that can adversely interact with RTNSS B systems are designed to the same seismic requirements as the affected RTNSS systems. On these bases, RAI 22.5-6 and the associated open item are resolved.

In addition, in RAI 22.5-7, the staff asked the applicant to discuss its specific application of the provisions of the IBC-2003 for the design of both equipment and structures meeting RTNSS Criterion B. In response, the applicant reiterated that Criterion B1 systems are designed to seismic Category II requirements, while the IBC-2003 is applied to the design of Criterion B2 systems as described below.

The maximum earthquake ground motion response spectrum is the single-envelope ESBWR SSE design response spectrum shown in DCD Tier 2, Revision 4, Figure 2.0-1. The following requirements apply to seismic Category I and II SSCs:

1. The RTNSS design ground motion spectrum is two-thirds SSE.
2. Structures, piping, or components, according to IBC-2003 Section 1616.3, must be designed as Seismic Design Category D under Seismic Use Group III with an importance factor of 1.5.

3. Equipment seismic loads must be calculated in accordance with American Society of Civil Engineers/Structural Engineering Institute 7-02, "Minimum Design Loads for Buildings and Other Structures," issued in 2002, Equations 9.6.1.3-1, 9.6.1.3-2, 9.6.1.3-3, and 9.5.2.7 for horizontal, maximum, minimum, and vertical loads, respectively.

The applicant also stated that the electrical building is an RTNSS structure. This building houses two nonsafety-related SDGs and provides space for the technical support center. The electrical building is nonsafety-related, nonseismic, and is designed to the Criterion B2 augmented design as described above.

Based on the staff's understanding of the IBC-2003, the augmented seismic design criteria, as delineated in the applicant's response, would allow Criterion B2 RTNSS SSCs to achieve the immediate occupancy performance level at two-thirds SSE. In accordance with FEMA 450, this is a state of some level of damage (lower for the structure and higher for the equipment) at two-thirds SSE. This is not sufficient to provide reasonable assurance that Criterion B2 SSCs will function after an SSE event. In RAI 22.5-7 S01, the staff therefore requested that the applicant do the following:

1. Provide a detailed explanation for the applicant's assertion that an immediate occupancy performance level at two-thirds SSE will provide reasonable assurance that Criterion B2 SSCs will function after an SSE event.
2. If applicable, provide in the DCD specific modifications to the IBC-2003 provisions to improve the performance criteria for RTNSS Criterion B2 SSCs to a functional performance level at an SSE event.

RAI 22.5-7 was being tracked as an open item in the SER with open items.

In response to RAI 22.5-7 S01, the applicant indicated that RTNSS buildings that house Criterion B2 systems are seismically designed in accordance with IBC-2003 using a dynamic analysis method with the SSE ground input motion equal to two-thirds of the CSDRS. An occupancy importance factor of 1.5, response modification factor of 2, and Seismic Design Category D/Seismic Use Group III apply to Criterion B2 structures.

In DCD Tier 2, Revision 5, Section 19A the applicant recategorized the SSCs in scope for RTNSS to address long-term safety and seismic requirements as Criterion B, thus eliminating the Criterion B1 and Criterion B2 groupings. All RTNSS Criterion B SSCs are designed to seismic Category II design criteria, which provides assurance that this equipment will have adequate capacity to survive an SSE and perform the required long-term safety functions. Based on this response, RAI 22.5-7 and the associated open item are resolved.

In DCD Tier 2, Revision 4, Section 19A.8.1, the applicant stated that regulatory oversight for RTNSS systems is categorized as high regulatory oversight (HRO), low regulatory oversight (LRO), or support. In Section 19A.8.3, the applicant also stated that the augmented design standards apply to HRO and LRO systems that meet Criterion B. Since the applicant designated many of the RTNSS Criterion B systems as regulatory oversight "support" in DCD Tier 2, Revision 4, Table 19A-2, the staff issued RAI 22.5-21, which requested that the applicant identify the standards used for the design of the RTNSS systems designated as "support." RAI 22.5-21 was being tracked as an open item in the SER with open items.

In its response to RAI 22.5-21, the applicant stated that it addressed the standards used to design RTNSS systems that provide support functions and the structures that house or support them in its response to RAI 22.5-5. In its response to RAI 22.5-5, the applicant committed to add supporting information to DCD Tier 2, Revision 5, Section 19A and provided a description of the proposed changes to the DCD. Specifically the response to RAI 22.5-5 included Tables 19A-3, "Structures Housing RTNSS Functions," and 19A-4, "Capability of RTNSS Related Structures." Table 19A-3 lists the systems identified as B1 and B2, the buildings in which they are housed, and their seismic category. Table 19A-4 lists the system locations and the treatment for internal flooding, external flooding, internal missiles, and extreme winds and missiles. With respect to external flooding and external missiles, GEH indicated that seismic Category I design provides the necessary level of protection. For nonseismic class buildings, the flood design accounts for hydrostatic pressure and requires that any openings below flood level be appropriately sealed. For missile protection in nonseismic class buildings (electrical and service water), the structures are designed to withstand Category 5 hurricanes and missiles. The turbine building is designed for tornado wind speeds without missiles; this design provides the required level of protection.

The staff considered the applicant's response to RAI 22.5-21 to be incomplete because it did not address seismic design. DCD Tier 2, Revision 4, Section 19A.8.3, stated that all systems that meet RTNSS Criterion B require augmented design standards. The same section excluded some of these systems because they were classified as "support" for purposes of regulatory treatment.

In RAI 22.5-21 S01, the staff requested the applicant to do the following:

1. Confirm that the augmented seismic design standards in DCD Tier 2, Revision 4, Section 19A.8.3, are applicable to all RTNSS systems and components that meet Criterion B, including those designated as regulatory oversight "support." Otherwise, describe the alternative seismic design criteria used and justify its adequacy.
2. Confirm that the augmented seismic design standards in DCD Tier 2, Revision 4, Section 19A.8.3, are applicable to the nonseismic structures that house and support all RTNSS systems and components that meet Criterion B including those designated as regulatory oversight "support." Otherwise, describe the alternative seismic design criteria used and justify its adequacy.

In response to RAI 22.5-21 S01, the applicant indicated that systems classified as "support" in DCD Tier 2, Revision 4, Section 19A.8.3, are LRO and thus are not excluded from the augmented design requirements. DCD Tier 2, Revision 5, clarified this assertion. Specifically, Section 19.8.1 clarified that "support" systems receive LRO, and Section 19A.8.3 clarified that all RTNSS B systems are housed in buildings that meet augmented design standards. Table 19A-3 identified all structures housing RTNSS B components; all structures in the list are either seismic Category I or II. Based on the clarifications and the table added to DCD Tier 2, Revision 5, RAI 22.5-21 S01 and the associated open item are resolved.

In DCD Tier 2, Revision 4, Section 19A.8.3, with respect to wind design for RTNSS components, the staff noted that the applicant committed to design Criterion B systems to withstand winds and missiles generated from Category 5 hurricanes. However, the applicant did not provide wind design parameters and missile characteristics. In addition, the applicant stated that the plant design for safety-related SSCs satisfies GDC 2 and meets the requirements of RG 1.59 and RG 1.102 with regard to developing flood design criteria and

protection against flood. However, the applicant did not note that these design criteria and RGs are used in the flood design and protection of RTNSS systems. In RAI 22.5-9, the staff asked the applicant to discuss key examples for demonstrating how the stated deterministic evaluation requirements are implemented for the RTNSS systems. RAI 22.5-9 was being tracked as an open item in the SER with open items.

In response to RAI 22.5-9, the applicant stated that it addressed the standards used to design RTNSS systems that provide support functions and the structures that house or support them in its response to RAI 22.5-5, in which it committed to adding supporting information to DCD Tier 2, Revision 5, Section 19A. The response to RAI 22.5-5 included Tables 19A-3 and 19A-4. Table 19A-3 lists the systems identified as B1 and B2, the buildings in which they are housed, and their seismic category. Table 19A-4 lists the system locations and the treatment for internal flooding, external flooding, internal missiles, and extreme winds and missiles. With respect to external flooding and external missiles, GEH indicated that the seismic Category I design provides the necessary level of protection. For nonseismic class buildings, the flood design accounts for hydrostatic pressure and requires that any openings below flood level be appropriately sealed. For missile protection in nonseismic class buildings (electrical and service water), the structures are designed to withstand Category 5 hurricanes and missiles. The turbine building is designed for tornado wind speeds without missiles, which provides the required level of protection.

The staff accepts the external flood design considerations for all classes and the missile protection assessment for seismic Category I structures. However, the applicant did not provide enough details regarding the impact of hurricanes and missiles on the nonseismic class structures.

In RAI 22.5-9 S01, the staff therefore requested that the applicant do the following:

1. Identify the 3-second gust wind speed used in the design for the Category 5 hurricane.
2. Confirm that the procedures used for calculating and distributing the wind pressure and all of the associated parameters that account for the physical and geometrical conditions of the structures are in accordance with DCD Tier 2, Revision 4, Section 3.3.1. Otherwise, fully describe the alternative procedure used.
3. Confirm that the hurricane missile spectrum is consistent with the tornado missile spectrum identified in DCD Tier 2, Revision 4, Table 2.0-1. Otherwise, fully describe the alternative missile spectrum used.
4. Explain how the design of the turbine building for tornado winds without missiles will envelop the demands of a Category 5 hurricane wind with missiles. If hurricane missiles are assumed to penetrate the building, describe the protection provisions implemented to protect RTNSS systems from missile damage as stated in Table 19A-4.

In reply to RAI 22.5-9 S01, the applicant stated that the design uses a wind speed of 314 kilometers (km) per hour (195 miles per hour [mph]), with a 3-second gust. The seismic Category I and II structures that house Criterion B systems are designed in accordance with provisions discussed in DCD Tier 2, Revision 5, Section 3.3.1. The standard hurricane missile used to determine impact resistance is consistent with "Design and Construction Guidance for Community Safe Rooms."

FEMA 361, "Design and Construction Guidance for Community Safe Rooms" was issued by the FEMA in 2000. The missile impact velocity is equal to the hurricane wind speed of 314 kilometers (km) per hour (195 mph), with a 3-second gust, multiplied by the shape factor for horizontal and vertical travel. In addition, the turbine building is designed for tornado winds, hurricane Category 5 winds, and missiles generated by hurricanes.

The staff considered the applicant's response to RAI 22.5-9 S01, to be incomplete because GEH did not indicate that it would revise the DCD as requested. The necessary information describes design criteria and must be included in the DCD. In addition, the staff found that the applicant had not adequately justified its proposed missile spectrum. In RAI 22.5-9 S02, the staff requested that the applicant do the following:

1. Include the 314 kilometers (km) per hour (195 mph), 3-second gust wind speed associated with Category 5 hurricanes in the DCD Tier 2, Revision 5.
2. Justify the use of the FEMA 361 wood stud missile as an appropriate missile for the design of nuclear facility or assume that the hurricane missile spectrum is consistent with the tornado missile spectrum identified in DCD Tier 2, Revision 5, Table 2.0-1, which is also consistent with the staff's implementation of SECY-96-128 delineated in the staff's memorandum to the Commission dated June 23, 1997 and titled, "Implementation of Staff Position in SECY-96-128, 'Policy and Key Technical Issues Pertaining to the Westinghouse AP600 Standard Pressurized Reactor Design,' Related to Post-72 Hour Actions."
3. Provide the design criteria associated with the hurricane missile in the DCD.

In its response to RAI 22.5-9 S02, the applicant indicated that it would change the hurricane missile spectrum to be consistent with the tornado missile spectrum identified in DCD Tier 2, Revision 5, Table 2.0-1. The applicant would revise DCD Tier 2, Revision 5, Section 19A.8.3 and Table 19A-4, to include the hurricane missile spectrum description and the design criteria associated with it. The design criteria associated with hurricane missiles follows DCD Tier 2, Revision 5, Section 3.5, for missiles generated by natural phenomenon. The tornado wind speed is substituted with the hurricane wind speed to design the concrete or steel barriers against missile impact. The staff confirmed that these changes were incorporated in DCD Tier 2, Revision 6, Section 19A.8.3 and Table 19A-4. Based on that, RAI 22.5-9 and the associated open item are resolved.

In RAI 22.5-25, with regard to the seismic design criteria for RTNSS Criterion C SSCs discussed in DCD Tier 2, Revision 4, the staff requested that the applicant do the following:

1. Provide a comparison to support the assertion that nonseismic structures that are designed to the IBC-2003 will maintain a structural integrity with a margin of safety that is equivalent to a seismic Category I structure under SSE. In this comparison, address all aspects of the two design and analysis methodologies including the design load combinations, the response modification factors (or energy absorption factors), member capacity reduction factors, construction detailing, the treatment of vertical seismic loads, and the treatment of concurrent orthogonal seismic components. Otherwise, remove this assertion from the DCD Tier 2.
2. Justify that qualifying RTNSS Criterion C equipment by using IEEE Std 344 to only demonstrate structural integrity will be sufficient to ensure the equipment functionality following an SSE event. Otherwise, if the functionality of these systems is not required after

an SSE seismic event, provide a statement in DCD Tier 2, Revision 5, to clarify that assertion.

In response, the applicant agreed to remove the phrase “with a margin of safety that is equivalent to a seismic Category I structure” to describe the design of nonseismic structures using IBC-2003. In addition, the applicant stated that RTNSS Criterion C components are not required to remain functional following a seismic event. The SMA results indicate that RTNSS Criterion C components are not required to function in order to avoid core damage following a seismic event. The staff confirmed that the applicant revised DCD Tier 2, Revision 4, Section 19A.8.3, to reflect the changes and clarified the functionality requirement for RTNSS Criterion C. Therefore, RAI 22.5-25 is resolved.

In RAI 22.5-5, the staff asked the applicant to describe how RTNSS systems will be protected specifically from the following:

1. Flood-related effects associated with both high- and moderate-energy fluid piping and component failures inside and outside containment
2. Flood-related effects associated with both natural phenomena and system and component failures
3. Piping failures in fluid systems outside containment
4. Missiles

In response to RAI 22.5-5, GEH provided Tables 19A-3 and 19A-4. In Table 19A-3, GEH identified the RTNSS SSCs together with their associated RTNSS criteria, locations (buildings), and building category. In Table 19A-4, GEH identified how the structures housing RTNSS SSCs in each area are protected from internal flooding, external flooding, internal missiles, and extreme wind and missiles.

The staff found the GEH response to RAI 22.5-5 inadequate. Specifically, GEH did not provide sufficient details to demonstrate that RTNSS systems had been adequately protected from flood-related effects associated with both natural phenomena and system and component failures. Subsequently, in RAI 22.5-5 S01, the staff requested that GEH provide a detailed description of the design and installation of each RTNSS SSC and discuss how this design and installation would provide the protection against the effects of internal or external flooding or both. RAI 22.5-5 was being tracked as an open item in the SER with open items.

In response to RAI 22.5-5 S01, GEH stated the following:

- RTNSS components are located and installed above the maximum analyzed flood levels in each of the buildings referenced. This requirement is incorporated in the design specifications and implemented during the detailed design to ensure protection of the RTNSS components against internal flooding.
- The maximum flood level for the ESBWR is one ft below the finished grade per DCD Tier 2, Revision 5, Table 2.0-1. The maximum groundwater level is two ft below the finished grade. The PSWS, located outdoors, is designed with protection from water intrusion if installed below the maximum flood and

groundwater levels. This includes designing for hydrostatic loading and provision of cell enclosures. These requirements are incorporated in the design specifications and implemented during detailed design.

The staff found the GEH response to RAI 22.5-5 S01 acceptable providing that DCD Tier 1, included design descriptions and ITAAC to ensure that RTNSS systems would be protected against internal flooding, external flooding, internal missiles (inside and outside containment), and extreme wind and missiles, as stated in DCD Tier 2, Revision 5. Therefore, in RAI 22.5-5 S02, the staff requested that GEH provide ITAAC in DCD, Tier 1, Section 2.0 to ensure that RTNSS systems will be protected against the following:

- Flood-related effects associated with both high- and moderate-energy fluid piping and component failures inside and outside containment
- Flood-related effects associated with both natural phenomena and system and component failures
- Internally-generated missiles (inside and outside containment)
- Externally-generated missiles

In response to RAI 22.5-5 S02, GEH stated that it would revise DCD Tier 2, Revision 5, to include ITAAC, as marked in the response, for RTNSS to ensure that the RTNSS systems would be protected against flood-related effects associated with both high- and moderate-energy fluid piping and component failures inside and outside containment, flood-related effects associated with both natural phenomena and system and component failures, postulated piping failures in fluid systems outside containment, internally-generated missiles (inside and outside containment), and externally-generated missiles.

The staff verified that these modifications and ITAAC were added in DCD Tier 2, Revision 6. These modifications assure that the features protecting safety-related SSCs and RTNSS SSCs against internal flooding, external flooding, internal missiles (inside and outside containment), and extreme wind and missiles are designed and will perform as described in DCD Tier 2, Revision 9. Therefore, the staff concludes that the ESBWR protection provided for safety-related SSCs and RTNSS SSCs against internal flooding, external flooding, internal missiles (inside and outside containment), and extreme wind and missiles complies with the requirements of 10 CFR 52.47(b)(1). In addition, the staff considers its concerns, as described in RAI 22.5-5, RAI 22.5-5 S01, RAI 22.5-5 S02, and the associated open item to be resolved.

22.5.6.3.2 Containment Integrity

The containment integrity safety function removes reactor decay heat and controls containment pressure to maintain containment integrity for the duration of an accident. In addition, if the containment pressure approaches the design value during a LOCA, it is necessary to provide a means to rapidly reduce the pressure to an acceptably lower value and to maintain this low value.

The passive systems that remove reactor decay heat from the core and containment are the safety-related ICS and the safety-related PCCS. These systems are capable of removing decay heat for at least 72 hours without the need for active systems or operator actions.

Section 19.1.6.1 of this report discusses the ability of the ICS to perform the decay heat removal

function in Mode 5. After 72 hours, makeup water is needed to replenish the boiloff from the upper containment and spent fuel pools. Initially, makeup water is provided by opening the IC/PCCS cross-connect valves. In the longer term, the FPS provides makeup to the pools via piping in the FAPCS. In DCD Tier 2, Revision 9, Section 19A.3.1.2, the applicant identified the following equipment relied upon to accomplish this makeup function:

- Diesel-driven FPS pump
- Fire water storage tank
- Diesel-driven pump fuel storage tank
- Piping in the FPS
- Piping in the FAPCS

The applicant stated in DCD Tier 2, Revision 9, Section 9.5.1.1, that the diesel-driven pump and piping in the FPS meet the augmented design requirements listed in DCD Tier 2, Revision 9, Section 19.A.8.3. This equipment will be designed in accordance with the seismic Category I standard, which the staff finds acceptable. This equipment is protected from natural phenomena, as discussed in Section 22.5.6.3.1 of this report.

In DCD Tier 2, Revision 9, Section 9.5.1.4, the applicant stated that the fuel oil tank for the primary diesel-driven fire pump has a capacity of 3785 liters (1,000 gallons), and, with such a capacity, the diesel-driven fire pump can provide makeup water to the ICS/PCCS pools from 72 hours to seven days after an accident. To determine the capacity, the applicant assumed that the diesel-driven pump need not operate continuously to supply the required quantity of makeup water to the pools because the flow rate required for performing this function is less than the flow rate required for supplying firewater. Consequently, the fuel capacity required before tank refilling is based on fuel consumption for injecting the required makeup quantity rather than operation of the diesel engine for approximately 96 hours. The staff finds this approach acceptable because the assumptions are realistic and reasonable.

The water for makeup is stored in the FPS primary storage tanks, which are designed to the seismic Category 1 standard and, together, hold over 3.7 million liters (1 million gallons) of water. In DCD Tier 2, Revision 9, Section 9.5.1.4, the applicant stated that these tanks have sufficient capacity to meet total demand in the post-72-hour period up to seven days following an accident. After seven days, onsite or offsite makeup sources can be used. Given the expected decay heat level for the ESBWR in the 4-day, post-72-hour period, more than enough water will be available in the storage tanks to make up for boiloff in the upper containment pools.

The ACM, documented in DCD Tier 2, Revision 9, Section 19ACM, and discussed in Section 22.5.9 of this report, provides the short-term ACs for the equipment listed herein.

The equipment identified by the applicant is sufficient to perform the makeup function in the post-72-hour period for up to seven days and satisfies the regulatory criteria listed in Section 22.5.6.2 of this report.

The ability to maintain containment pressure for the first 72 hours is accomplished by removing decay heat using the PCCS. Noncondensable gas accumulation in the drywell causes containment pressure to trend upward. After 72 hours, nonsafety-related systems in the scope of RTNSS function in conjunction with PCCS to maintain containment pressure acceptably low for the long term. The passive autocatalytic recombiners (PARs) in the containment airspaces and PCCS vent fans function to mitigate the pressure increase due to noncondensable gas

accumulation. The PARs remove hydrogen and oxygen generated by radiolysis. They do not require supporting power. The PCCS vent fans redistribute the noncondensable gases from the wetwell to the drywell to reduce overall containment pressure to an acceptable level. The PCCS vent fans are powered from the ancillary ac power buses and are manually aligned and operated. Section 22.5.6.3.4 of this report discusses the ancillary ac power system.

22.5.6.3.3 Core Cooling

The core cooling safety function is to provide an adequate inventory of water to ensure that the fuel remains cooled and covered, with stable and improving conditions, beyond 72 hours. For scenarios with the reactor coolant system intact, the safety-related ICS performs this function; for scenarios with the reactor coolant system open to containment, the safety-related GDACS injection function meets this requirement. As long as decay heat removal is ensured in the post-72-hour period (i.e., makeup water is provided to the upper containment pools as needed), the GDACS provides a sustainable, closed-loop method to keep the core covered. Consequently, the applicant concluded that neither nonsafety-related equipment nor operator actions are directly relied upon to support the core cooling safety function, and there are no RTNSS requirements to support post-72-hour core cooling.

Based on its review of the ICS and GDACS designs documented in Sections 5.4.6 and 6.3 of this report, respectively, the staff agrees that these systems can perform the post-72-hour core cooling function as long as makeup water is provided as described in Section 22.5.6.3.2 above. Therefore, the staff finds the applicant's proposed treatment of the core cooling safety function to be acceptable.

22.5.6.3.4 Control Room Habitability

Safety-related portions of the control room habitability area ventilation system (CRHAVS) maintain control room habitability. This function is operated on safety-related battery power for the first 72 hours following an event. The nonsafety-related ancillary ac power system provides backup power (post-72 hours) to the safety-related control room emergency filtration unit (EFU) fans. In addition, the control room habitability area (CRHA) air-handling units (AHUs) and auxiliary cooling units maintain control room temperatures within limits in the post-72 hour period. Consequently, the applicant has identified the components of the ancillary ac power system and the CRHA AHUs as nonsafety components requiring regulatory treatment under the RTNSS process.

The components of the ancillary ac power system include redundant ancillary DGs, buses, diesel fuel storage tanks, and diesel fuel transfer pumps. These components reside in the ancillary DG building, which is a seismic Category II structure. The CRHA AHUs reside in the control building, which is a seismic Category I structure. As discussed in Section 22.5.6.3.1 of this report, the applicant has committed to applying its augmented design standards to equipment required for long term cooling, which includes this equipment, and the staff has found these standards to be acceptable.

The applicant has included ACs for the ancillary ac power system components and the CRHA AHUs in Section 19ACM of the ACM. The staff reviewed the ACs for the ancillary ac power system. In RAI 22.5-46, the staff asked the applicant to add the following availability control surveillance requirement (ACSR) for ancillary DGs:

1. Verify that each ancillary diesel generator starts and operates at rated load for ≥ 24 hours. This test may utilize diesel engine pre-lube prior to starting and warm-up period prior to loading. Also, verify this test is done during every refueling outage.
2. Verify the fuel oil transfer system operates to [automatically] transfer fuel oil from storage tank[s] to the day tank [and engine mounted tank]. Also, verify this test is done every 92 days.

In response, the applicant stated it would revise Availability Control Limiting Condition for Operation (ACLCO) 3.8.3 to include the requested ACSR and corresponding bases. The staff confirmed that the applicant incorporated the requested ACSR and bases into DCD Tier 2, Revision 7. The staff finds that the applicant has adequately addressed the issue, and the RAI is resolved. The staff reviewed the ACs for the CRHA AHUs and their bases and finds them acceptable because they are similar to typical surveillance requirements for this type of equipment in operating reactors.

22.5.6.3.5 Postaccident Monitoring

Postaccident monitoring safety functions include safety-related displays in the control room, emergency lighting, and control room cooling to remove heat generated by personnel and the monitoring equipment. The safety-related digital control and instrumentation system (Q-DCIS) provides postaccident monitoring (DCD Tier 2, Revision 9, Section 7.1.2.8) and is safety-related and normally powered by uninterruptible power, including dc batteries designed to function for at least 72 hours. Emergency lighting, which is normally powered by 72-hour batteries, is provided to support postaccident monitoring functions. Passive cooling, provided by the control building and reactor building structures, maintains the equipment within acceptable temperature limits for at least 72 hours.

For the post-72-hour period, the CRHA AHUs and auxiliary cooling units maintain control room temperatures within limits. Beyond 72 hours, it is necessary to provide power for the Q-DCIS components. Ancillary ac power supplies the power for the Q-DCIS and emergency lighting (DCD Tier 2, Revision 9, Section 9.5.3). The Q-DCIS cabinets and related components are either passively cooled, or if necessary, have localized cooling from the CRHAVS recirculation AHUs. Ancillary ac power also provides power for the recirculation AHUs.

The applicant has included the ancillary ac power system, the CRHA AHUs and auxiliary cooling units, and the CRHAVS in the RTNSS program. The staff reviewed the ACs for the CRHAVS and their bases, and finds them acceptable. Section 22.5.6.3.4 of this report discusses the staff's review of the CRHA and ancillary ac power system.

22.5.6.4 Conclusions

The staff finds that the applicant has included sufficient nonsafety-related equipment in the RTNSS program to ensure that safety functions relied upon in the post-72-hour period are successful. Further, the staff finds that the nonsafety-related equipment relied upon in the post-72-hour period has been designed in accordance with Commission policy and that the applicant has established appropriate ACs for this equipment.

22.5.7 Mission Statements and Regulatory Oversight of Important Nonsafety-Related Structures, Systems, and Components

22.5.7.1 Summary of Technical Information

In accordance with the RTNSS process, nonsafety-related SSCs relied upon to meet the criteria described in Section 22.2 of this report are designated as RTNSS important and are subject to regulatory oversight. As described in Sections 22.5.1 through 22.5.6 of this report, the applicant has identified the RTNSS-important SSCs. In DCD Tier 2, Revision 9, Section 19A.8.4, the applicant identified these important nonsafety systems, their missions, and recommended regulatory oversight. Table 19A-2 in DCD Tier 2, Revision 9, lists the included SSCs.

The applicant stated in DCD Tier 2, Revision 9, Section 19A.8.2, that all RTNSS systems must be in the scope of the design reliability assurance program (D-RAP), as directed by DCD Tier 2, Revision 9, Section 17. The COL applicant's Maintenance Rule program, which is regulated in accordance with 10 CFR 50.65, will incorporate the D-RAP.

In DCD Tier 2, Revision 9, Section 19A.8.1, the applicant described its method for determining whether the TS or a separate process outside of the TS will control the availability of nonsafety-related SSCs requiring regulatory oversight. The applicant's decision process relies on the results of the focused ESBWR PRAs, and in particular, on the focused PRA sensitivity studies that show the importance of SSC functions in keeping CDF and LRF below the Commission's established goals. In these focused PRA studies, each RTNSS system was failed with all other RTNSS equipment credited. In cases in which the result exceeded a CDF or LRF goal, the SSC was identified as risk significant, requiring that the TS control availability. The only RTNSS function satisfying this criterion was the diverse actuation of ECCS functions that the DPS TS controls. The ACM, discussed in Section 22.5.9 of this report, addresses the ACs of the other RTNSS systems.

22.5.7.2 Regulatory Criteria

The applicable regulatory criteria include (1) 10 CFR 50.36(c)(2)(ii)(D), which requires that a TS LCO of a nuclear reactor be established for an SSC that either operating experience or a PRA has shown to be significant to public health and safety, and (2) RG 1.206, which describes the scope, criteria, and process used to determine RTNSS in the passive plant designs.

22.5.7.3 Staff Evaluation

The mission of the DPS is to provide diverse actuation functions that will enhance the plant's ability to mitigate dominant accident sequences involving the common-cause failure of actuation logic or controls. In DCD Tier 2, Revision 9, Section 19A.8.4.5, the applicant stated that it has established generic technical specification (GTS) operability, action, and surveillance requirements for the DPS. GTS 3.3.8.1 specifies the DPS instrumentation and actuation functions. The following GTSs specify the associated DPS initiators of safety-related valves for the identified system:

- GTS 3.5.1 and GTS 3.5.3 for the ADS
- GTS 3.5.2 and GTS 3.5.3 for the GDCCS
- GTS 3.6.1.3 for RWCU/SDC system containment isolation
- GTS 3.7.1 for opening of the equipment pool-to-inner expansion pool cross-connect valves

In light of the results of the focused ESBWR PRA and the requirements of 10 CFR 50.36(c)(2)(ii)(D), the staff finds this acceptable.

The staff has reviewed the mission statements for SSCs provided in DCD Tier 2, Revision 9, Section 19A.8.4. These statements correctly describe the missions of RTNSS and nonsafety-related SSCs; therefore, the staff finds them acceptable.

The staff reviewed the provisions in DCD Tier 2, Revision 4, for the oversight of nonsafety-related SSCs. In RAI 22.5-16, the staff asked the applicant to provide additional information regarding the treatment of several systems and components. The applicant provided a response for each of those systems or components and referred to the ACM or other sections of the DCD. However, the treatment provisions for several SSCs were not explained in sufficient detail and consequently, RAI 22.5-16 was being tracked as an open item in the SER with open items.

In RAI 22.5-16 S01, the staff asked the applicant to clarify the treatment provisions for RTNSS SSCs. In response to RAI 22.5-16 S01, the applicant clarified the treatment provisions for the RTNSS SSCs. Based on the Commission's guidance and experience with other risk-informed industry programs, the staff considers the treatment provisions described for these RTNSS SSCs, combined with other relevant provisions in DCD Tier 2, Revision 9, to be sufficient for the ESBWR design certification review. Therefore, RAI 22.5-16 and the associated open item are resolved.

DCD Tier 2, Revision 5, Section 19A.2.1, states that most of the SLC system is safety-related and has sufficient regulatory oversight. In RAI 22.5-15, the staff asked the applicant to clarify those portions of the SLC system that are nonsafety-related, as well as the regulatory oversight specified for those components. The staff also asked the applicant to justify the basis for stating that regulatory oversight of the SLC system is sufficient, since some portions of the SLC system are categorized as nonsafety-related and not included in RTNSS. In response to RAI 22.5-15, the applicant clarified the function of the nonsafety-related portions of the SLC system. These portions include the subsystem for nitrogen charging of the accumulators and the subsystem for boron mixing and makeup of the accumulators. These systems are not required for the SLC to perform its safety-related function. They are used to maintain SLC readiness.

In RAI 22.5-15 S01, the staff requested that the applicant discuss the nonsafety-related systems or components used to monitor the operational readiness of the SLC system and explain why they are not included in the RTNSS program. In response to RAI 22.5-15 S01, the applicant stated that the TS control the operational readiness of the SLC system and supporting systems. The staff found this response to be acceptable because TS controls provide adequate oversight. Therefore, RAI 22.5-15 S01 is resolved.

In RAIs 22.5-28 and 22.5-29, the staff asked the applicant to clarify the regulatory oversight provisions for RTNSS SSCs in Section 19A.8.1 and the treatment of specific systems in Section 19A.8.4. In response to these RAIs, the applicant provided planned modifications to DCD Tier 2, to clarify the title of Section 19A.8.1, to address availability treatment, and to include Section 19A.8.4.13 and Section 19A.8.4.14, to reference the applicable regulatory treatment for these functions. DCD Tier 2, Revision 7, included these modifications, which provide an acceptable clarification of the regulatory oversight provisions for RTNSS functions and the regulatory treatment for the specified systems.

DCD Tier 2, Revision 4, Section 17.4, describes the D-RAP, which contains requirements for the treatment of risk-significant SSCs, including RTNSS systems. The D-RAP is used during the design and specific equipment selection phases to ensure that the important ESBWR reliability assumptions in the PRA are considered throughout the plant life. The D-RAP identifies relevant aspects of plant operation, maintenance, and performance monitoring of important plant SSCs for consideration in ensuring the safety of the equipment and providing for protection of the public. GEH ESBWR engineering design procedural controls are applied to the D-RAP, with specific procedures for design process, control of design changes, and storage and retrieval controls. The design control procedure defines the process for performing, documenting, and verifying design activities, including developing or modifying the design of systems, engineering evaluations, analyses, calculations, and documents. The staff has reviewed the proposed reliability assurance program and documented its review in Section 17.4 of this report. The staff finds that the reliability assurance program meets the guidance in Item E of SECY-95-132 and Section 17.4 of the SRP.

DCD, Tier 1, Revision 9, Section 3.6 includes an ITAAC for the D-RAP. As noted above, DCD Tier 2, Revision 9, Section 17.2, includes COL information items that require the COL applicant to describe the quality assurance program for the construction and operations phases and the quality assurance program for design activities that are necessary to adapt the certified standard plant design to a specific plant implementation. The NRC will conduct its evaluation of these activities as part of the COL application reviews and construction inspection programs.

In DCD, Tier 1, Revision 4, Section 2.12.2, Section 2.12.5, and Section 2.12.7 the applicant revised the ITAAC to remove large portions of information, including a system description, system drawings, a design commitment, and ITAAC scope. The staff found the removal of this ITAAC information in Tier 1 to be unacceptable. In RAls 22.5-1 and 22.5-1 S01, the staff requested that the applicant review and revise DCD, Tier 1 to include the RCCWS, chilled water system (CWS), and the PSWS in Tier 1 for ITAAC. In response to the RAls, the applicant provided the requested Tier 1 system description, ITAAC, and drawings for the RCCW, CWS, and PSWS in the revised DCD, Tier 1 sections. DCD, Tier 1, Revision 5 incorporated this information; therefore, the staff finds that RAls 22.5-1 and 22.5-1 S01 are resolved. Section 9.2 of this report also discusses closure of these RAls.

22.5.8 Technical Specifications

As discussed in Section 22.5.7.1 of this report, the applicant committed to include in DCD Tier 2, Sections 16 and 16B, the GTS and bases for the nonsafety-related functions of the DPS that have been determined to be risk significant. The applicant included TS and bases for the risk-significant nonsafety-related functions of the DPS in DCD Tier 2, Revision 6, Sections 16 and 16B. The staff reviewed the GTS and bases for these DPS functions as documented in Section 16.2.6 of this report, and finds them acceptable.

22.5.9 Short-Term Availability Controls

22.5.9.1 Summary of Technical Information

In DCD Tier 2, Revision 4, Section 19A.8.1, the applicant proposed a means for implementing RTNSS controls in the form of administrative ACs for the SSCs summarized in DCD Tier 2, Revision 4, Section 19A.8.4.1, and listed in Table 19A-2, except for the DPS manual controls, which are addressed by GTS 3.3.8.1, as discussed in SER Section 22.5.8. The ACM, which has been incorporated into DCD Tier 2, Revision 7, Section 19ACM, documents the ACs.

The RTNSS criteria, designated as “1” through “5” in the preceding evaluation, are designated as “A” through “E” in DCD Tier 2, Revision 9, Section 19A and in this section of the report. For each criterion, the identified associated RTNSS SSC functions are identified below. Also listed are those nonsafety-related functions or systems that are included in the GTS and those for which an explicit AC or GTS is not specified because they do not meet any of the criteria for establishing an AC or an LCO. The instrumentation and logic descriptions are taken from DCD Tier 2, Revision 9, Section 7. Table 22.5.9-1 summarizes the proposed ACs.

Criterion A: SSC functions relied upon to meet NRC deterministic performance requirements (beyond design-basis events)—10 CFR 50.62(c) and 10 CFR 50.63

Note: DCD Tier 2, Revision 9, Section 19A.2.2 states that there are no RTNSS candidates for SBO based on Criterion A.

- **(AC 3.3.1) ARI System**
 - Four ARI-associated instrumentation channels of nonsafety-related DPS, reactor pressure vessel (RPV) wide-range water-level sensors, and RPV dome pressure sensors supply the nonsafety-related DPS ARI trip logic.
 - Nonsafety-related DPS ARI trip logic function generates ARI trip signal to the three sets of ARI valves in the CRD system upon any of the following signals:
 - Two-out-of-four channels of the DPS high RPV dome pressure function are greater than or equal to the setpoint.
 - Two-out-of-four channels of the DPS low RPV water level function are less than or equal to the setpoint (i.e., Level 2).
 - Both ARI manual pushbuttons in the ATWS/SLC system actuated (causes manual actuation of ARI, SLC, and FWRB).
 - DPS diverse scram ATWS mitigation logic ARI trip signal on either of the following:
 - (GTS 3.7.6) SCRRI/SRI command with power remaining elevated (two-out-of-three logic)
 - (GTS 3.3.1.2) RPS scram command (two-out-of-four logic)
- **SLC System**
 - **(AC 3.3.2, Function 1)** Safety-related ATWS/SLC actuation logic automatically initiates SLC system boron injection for diverse reactor shutdown on any of the following signals:
 - Two-out-of-four channels of the safety-related high RPV dome pressure function are greater than or equal to the setpoint and two-out-of-four channels of the safety-related start-up range nuclear monitor (SRNM) ATWS permissive function are greater than or equal to the setpoint for at least three or more minutes.
 - Two-out-of-four channels of the safety-related low RPV water level function are less than or equal to the setpoint (i.e., Level 2) and two-out-of-four channels of the safety-related SRNM ATWS permissive function are greater than or equal to the setpoint for at least three or more minutes.
 - (GTS 3.1.7, GTS 3.3.5.1 Function 1, GTS 3.3.5.2 Function 4) Safety-related safety system logic and control (SSLC), SSLC/ESF actuation logic for ECCS injection for

LOCA mitigation automatically initiates the SLC system 50 seconds after receipt of the following signal:

- (GTS 3.3.5.1 Function 1) Two out of four channels of the safety-related low RPV water level function are less than or equal to the setpoint (i.e., Level 1) sustained for 10 seconds.
 - (GTS 3.3.5.2, Function 4) Safety-related ATWS/SLC actuation logic automatically closes the normally open, redundant, in series, fail-as-is accumulator shutoff valves to prevent nitrogen entry into the RPV on the following signal:
 - (GTS 3.1.7) Two-out-of-four channels of the safety-related low accumulator level function are less than the setpoint.
- **(AC 3.3.2, Function 2) RWCU/SDC System Isolation**—The SLC system logic transmits an isolation signal to the RWCU/SDC via the leak detection and isolation system (LD&IS), thus preventing dilution of boric acid in the RPV.
- **ADS Inhibit**
 - **(AC 3.3.2, Function 3)** Inhibit safety-related SSLC/ESF actuation logic for ADS actuation on two-out-of-four channels of sustained low RPV level function less than or equal to the setpoint (i.e., Level 1) and sustained drywell pressure high function greater than or equal to the setpoint by either of the following safety-related ATWS signals:
 - Coincident low RPV water level (i.e., Level 2) and average power range monitor (APRM) ATWS permissive signals
 - Coincident high RPV pressure function greater than or equal to its setpoint and APRM ATWS permissive signals that persist for 60 seconds
 - (No AC provided) Inhibit safety-related SSLC/ESF actuation logic for feedwater isolation on two-out-of-four channels of high-high drywell pressure function greater than or equal to the setpoint by either of the above safety-related ATWS signals.
 - **(AC 3.3.4, Function 7) DPS ADS Inhibit**
 - Inhibit nonsafety-related DPS actuation logic for diverse actuation of ADS on two-out-of-four channels of sustained DPS RPV level less than or equal to Level 1 by either of the following DPS ATWS signals:
 - Coincident low RPV water level (i.e., Level 2) and SRNM ATWS permissive signals
 - Coincident high RPV pressure function greater than or equal to its setpoint and SRNM ATWS permissive signals that persist for 60 seconds
- **(AC 3.3.3) Automatic FWRB** (analogous to BWR/6 recirculation pump trip) provides quick power reduction that prevents RPV overpressure and short-term fuel damage for ATWS events.
 - Safety-related ATWS/SLC mitigation logic generates the FWRB signal when two-out-of-four channels of high RPV dome pressure function and SRNM ATWS permissive function are greater than or equal to their setpoints.
 - Nonsafety-related DPS FWRB actuation logic function generates FWRB actuation signal to FWCS.
 - Nonsafety-related FWCS runs feedwater demand to minimum for quick power reduction.

- (No AC provided) Diverse scram by DPS diverse scram ATWS mitigation logic on either of the following signals:
 - (GTS 3.7.6) select control rod run-in/select rod insert (SCRRI/SRI) command with power remaining elevated (two-out-of-three logic)
 - (GTS 3.3.1.1) RPS scram command (two-out-of-four logic)
- (No AC provided) Delayed FWRB if elevated power levels persist by DPS diverse scram ATWS mitigation logic on either of the following signals:
 - (GTS 3.7.6) SCRRI/SRI command with power remaining elevated (two-out-of-three logic)
 - (GTS 3.3.1.1) RPS scram command (two-out-of-four logic)

Criterion B—SSC functions relied upon to ensure long-term safety (beyond 72 hours) and address seismic events (DCD Tier 2, Revision 9, Section 19A.3.2 states that there are no seismic-related candidates for RTNSS consideration.)

- **(AC 3.7.1)** Long-term core cooling—supports ICS and PCCS operation
- **(ACs 3.6.2, 3.6.3, 3.7.1)** Long-term containment integrity—control containment pressure; support ICS and PCCS operation
- **(AC 3.7.6)** Long-term control room habitability—CRHA temperature control; occupant radiation dose mitigation
- (GTS 3.3.3.2) Postaccident monitoring instrumentation—support operator actions needed to support SSC functions of long-term core cooling, containment integrity, and control room habitability
- **(AC 3.7.1)** Long-term spent fuel pool (SFP) cooling—supply SFP makeup
- **(AC 3.7.6)** Long-term cooling for postaccident monitoring instrumentation heat loads—CRHA temperature control
- The following SSCs are relied on to support Criterion B SSC functions:
 - **(AC 3.7.1)** FPS motor-driven and diesel-driven pumps (primary); FPS fire water storage tanks; FPS connections to FAPCS; safety-related FAPCS piping to IC/PCCS pools, and SFP; supply makeup to IC/PCCS pools and SFP
 - **(AC 3.6.3)** PCCS vent fans support PCCS for long-term control of containment pressure
 - **(AC 3.6.2)** PARs for long-term control of containment pressure
 - **(AC 3.7.6)** CRHAVS AHU fans and filters for long-term control room habitability by limiting occupant radiation dose
 - **(AC 3.7.6)** CRHAVS auxiliary cooling units and recirculation AHU fans—cool DCIS cabinets; maintain long-term control room habitability by removing heat to maintain control room temperature to cool Q-DCIS
 - **(AC 3.7.6)** Q-DCIS room local coolers—cool Q-DCIS cabinets

- (No AC provided) Emergency lighting—supports postaccident monitoring instrumentation
- (GTS Section 3.3) Q-DCIS—supports postaccident monitoring instrumentation
- **(AC 3.8.3)** Ancillary DGs—supply ancillary ac electrical power distribution buses; supported by ancillary DG building HVAC and ancillary DG fuel tanks and fuel transfer pumps
- **(AC 3.8.1 and 3.8.2)** SDGs—supply PIP buses; supported by standby DG fuel storage and fuel transfer system
- (No AC provided) PIP buses—supply ancillary ac electrical power distribution buses and ac power for FAPCS pumps
- (No AC provided) Ancillary ac electrical power distribution buses—supply ac power for Q-DCIS, emergency lighting, and CRHAVS supply AHU fans; CRHAVS recirculation AHU fans and auxiliary cooling units; Q-DCIS room local coolers, PCCS vent fans, and FPS motor-driven pump

Criterion C—SSC functions relied upon to meet Commission’s safety goal guidelines of $CDF < 1 \times 10^{-4}$ reactor-year⁻¹ and $LRF < 1 \times 10^{-6}$ reactor-year⁻¹ (focused PRA)

- **(AC 3.3.4, Function 1)** Diverse protection logics for reactor scram—provide backup to RPS scram functions when two-out-of-four channels are tripped for any of the following diverse scram instrumentation functions:
 - High RPV pressure
 - High RPV water level (i.e., Level 8) MSIV isolation
 - Low RPV water level (i.e., Level 3)
 - High drywell pressure
 - High suppression pool temperature
 - Closure of MSIVs
- (GTS 3.7.6) DPS SCRR/SRI Logic
- Diverse ESF logics for the following isolation actuation functions, which backup LD&IS isolation actuation functions:
 - **(AC 3.3.4, Function 2)** Diverse closure of MSIVs (enabled by mode switch in run position) on two-out-of-four channels tripped for any of the following diverse isolation instrumentation functions: high steam flow rate, low RPV pressure, or low RPV water level (i.e., Level 2)
 - **(GTS 3.3.8.1, Function 3.a)** Diverse closure RWCU/SDC isolation valves on two-out-of-four channels tripped for the diverse isolation instrumentation function of high RWCU/SDC differential flow rate
 - (No AC provided) Diverse isolation of feedwater lines (trips feedwater pumps and closes feedwater containment isolation valves) on feedwater line break inside containment or LOCA conditions that pose a challenge to containment design pressure on two-out-of-four channels tripped for any of the following diverse isolation instrumentation functions: differential pressure between feedwater lines coincident with high drywell pressure, high drywell pressure coincident with high drywell water level, or high-high drywell pressure

- (No AC provided) Diverse isolation of CRD high pressure makeup water injection on two-out-of-four channels tripped for either of the following diverse isolation instrumentation functions: high drywell pressure coincident with high drywell level or low level in two-out-of-three GDCS pools
- **(AC 3.3.4, Function 3) Diverse initiation of SRVs**
 - Diverse low RPV water level (i.e., Level 1) signals, sustained for 10 seconds, are evaluated in nonsafety-related triple redundant processors with a two-out-of-four coincident logic.
 - A coincident logic trip decision is required from two-out-of-three processors for each of the three output logic devices to generate the start (i.e., SRV open) signal.
 - Each of three in-series discrete output switches is actuated by the two-out-of-three voted start signal from its associated independent output logic device.
 - A valid initiation signal from all in-series output switches is required to generate diverse ECCS actuation (i.e., ADS function of the 10 SRVs).
- (GTS 3.3.8.1, Function 1.a) Diverse automatic initiation of ADS (open depressurization valves [DPVs])
 - Diverse low RPV water level (i.e., Level 1) signals, sustained for 10 seconds, are evaluated in nonsafety-related triple redundant processors with a two-out-of-four coincident logic.
- (GTS 3.3.8.1, Function 1.b) Diverse manual initiation of ADS (open DPVs)
 - Two-out-of-four diverse high drywell pressure signals are greater than or equal to the setpoint and are sustained for at least 60 minutes or more, which permits diverse manual initiation of ADS
- (GTS 3.3.8.1, Function 2.a) Diverse automatic initiation of GDCS injection
 - Diverse low RPV water level (i.e., Level 1) signals, sustained for 10 seconds, are evaluated in nonsafety-related triple redundant processors with a two-out-of-four coincident logic.
- (GTS 3.3.8.1, Function 2.b) Diverse manual initiation of GDCS injection
 - Two-out-of-four diverse high drywell pressure signals are greater than or equal to the setpoint and are sustained for at least 60 minutes or more, which permits diverse manual initiation of GDCS injection.
- (No AC provided) Diverse manual GDCS suppression pool equalization line actuation—not required until approximately 30 minutes after a LOCA
- **(AC 3.3.4, Function 4) FMCRD run-in—diverse control rod insertion**
 - On receipt of signals initiating ARI, as described above, the DPS generates an additional signal to the rod control and instrumentation system (RC&IS) to initiate electrical insertion of all operable control rods. The ARI and FMCRD run-in logic resides in the DPS.

- **(AC 3.3.4, Function 5)** Diverse initiation of ICS to provide core cooling on two-out-of-four channels tripped for any of the following diverse instrumentation channels: high RPV dome pressure, low RPV water level (i.e., Level 2), or MSIV closure.
- **(AC 3.3.4, Function 6)** Diverse ESF actuation logic for ECCS injection for LOCA mitigation automatically initiates the SLC system 50 seconds after receipt of the following signal:
 - Two-out-of-four channels of the nonsafety-related DPS low RPV water level function are less than or equal to the setpoint (i.e., Level 1) are sustained for 10 seconds.
- (GTS 3.3.8.1, Function 4.a) Diverse opening of cross-connect valves between the equipment storage pool and the IC/PCCS expansion pools when a low-level condition is detected in either of the IC/PCCS inner expansion pools, which provides long term core and containment cooling.
 - Two-out-of-four channels of the nonsafety-related DPS low IC/PCCS expansion pool water level function are less than or equal to the setpoint.
- **(AC 3.7.2, 3.7.3)** FAPCS low-pressure injection (diverse method of core cooling)
- **(AC 3.7.2, 3.7.3)** FAPCS suppression pool cooling (diverse method of containment heat removal)
- SSC functions relied upon to support Criterion C SSC functions include the following:
 - The following support Q-DCIS, N-DCIS, and DPS:
 - **(AC 3.7.6)** CRHA long-term cooling
 - **(AC 3.8.3)** ancillary DGs
 - Ancillary ac power distribution
 - Ancillary DG building HVAC
 - Reactor building HVAC local cooling
 - The following support FAPCS operation (pumps):
 - Fuel building HVAC which provides FAPCS pump room cooling—supported by the NICWS
 - RCCWS
 - PSWS which supports the RCCWS
 - **(AC 3.8.1, 3.8.2)** SDGs (onsite ac electrical power source)—supported by standby DG auxiliary systems, standby DG fuel oil storage and transfer system, and electrical building HVAC
 - PIP buses—ac electrical power distribution
 - N-DCIS
 - Turbine building HVAC local cooling

Criterion D—SSC functions needed to meet the containment performance goal, including containment bypass, during severe accidents of less than 0.1 CCFP—used qualitatively

- (AC 3.5.1) GDCS deluge function
- (AC 4.1) BiMAC device

Criterion E—SSC functions relied upon to prevent significant adverse system interactions

- (AC 3.6.1) Lower drywell hatches (personnel air lock and equipment hatch)
- (AC 3.7.5) Reactor building HVAC accident exhaust filtration

Table 22.5.9-1. Proposed Short Term Availability Controls.

AC	TITLE	RTNSS CRITERION—MISSIONS	SER SECTION
3.3.1	ARI System	A—ATWS Rule ATWS mitigation—automatically depressurize scram header on ATWS signal to initiate hydraulic scram	22.5.4.2
3.3.2	ATWS/SLC System Actuation Functions		
3.3.2	1. SLC Actuation	A—ATWS Rule ATWS mitigation—SLC diverse reactor shutdown using ATWS/SLC logic to actuate SLC system LOCA mitigation—RCS makeup high-pressure injection using ATWS/SLC logic to actuate SLC system	N/A Safety-Related
3.3.2	2. RWCU/SDC Isolation	A—ATWS Rule ATWS mitigation—support SLC diverse reactor shutdown by preventing dilution of RCS boric acid inventory using ATWS/SLC logic to close RWCU/SDC containment isolation valves	N/A Safety-Related
3.3.2	3. ADS Inhibit	A—ATWS Rule ATWS mitigation—support SLC diverse reactor shutdown by maintaining RCS boric acid inventory using ATWS/SLC logic to prevent SRV and DPV opening by SSLC/ESF	N/A Safety-Related

AC	TITLE	RTNSS CRITERION—MISSIONS	SER SECTION
3.3.3	FWRB (logic processed by DPS)	A—ATWS Rule ATWS mitigation—run feedwater demand to minimum for quick power reduction	22.5.4.2.1 22.5.4.2.3
3.3.4	DPS backup functions not required by LCO 3.3.8.1	Not needed to meet CDF and LRF goals; included for mitigation of common-mode failure.	
3.3.4	1. Reactor Scram	C—Focused PRA Accident mitigation—initiation of hydraulic scram diverse from RPS	22.5.1.1.1
3.3.4	2. MSIV Closure	C—Focused PRA Accident mitigation—actuation of main steamline isolation diverse from SSLC	22.5.1.1.1
3.3.4	3. SRV Actuation	C—Focused PRA Accident mitigation—actuation of reactor vessel depressurization diverse from SSLC to support low-pressure injection	22.5.1.1.1
3.3.4	4. FMCRD Run-In Actuation	C—Focused PRA Accident mitigation—initiation of electrical insertion of control rods diverse from RPS	22.5.1.1.1
3.3.4	5. ICS Actuation	C—Focused PRA Accident mitigation—ICS actuation diverse from SSLC	22.5.1.1.1
3.3.4	6. SLCS Actuation (for LOCA)	C—Focused PRA LOCA mitigation—actuation of SLC system high-pressure RCS makeup diverse from SSLC	22.5.1.1.1
3.3.4	7. ADS Inhibit	A—ATWS Rule ATWS mitigation—support SLC diverse reactor shutdown by maintaining RCS boric acid inventory; diverse from SSLC	22.5.4.2.1 22.5.4.2.3
3.5.1	GDCS Deluge Function	D—Containment Performance Automatic flood of lower drywell and BiMAC device to cool and protect containment from core melt debris	22.5.2.1

AC	TITLE	RTNSS CRITERION—MISSIONS	SER SECTION
3.6.1	Lower Drywell Hatches (personnel air lock and equipment hatch)	E—Adverse System Interactions Mitigate shutdown LOCA by preventing coolant from draining out of the lower drywell	22.5.5.1 22.5.5.3
3.6.2	PARs	B—Long-Term Containment Integrity Long-term containment pressure control by recombining hydrogen and oxygen	22.5.6.3.2
3.6.3	PCCS Vent Fans	B—Long-Term Containment Integrity Forced circulation of steam and noncondensable gas in drywell and wetwell atmosphere through PCCS condensers post-72 hours	22.5.6.3.2
3.6.4	Hydrogen Mitigation – Ignitors	D—Containment Performance Ignitors (glow plugs) in the lower drums of the PCCS condensers recombine the hydrogen and oxygen while they are still at lower concentrations, thus preventing a detonation that could result from the accumulation of high concentrations of these gases.	22.5.2.1 22.5.2.3
3.7.1	Emergency Makeup Water Functions (FPS—Diesel and Motor-Driven Pumps; FPS to FAPCS Connection Piping; FPS Water and Diesel Fuel Tanks)		
3.7.1	1. IC/PCCS Pools Makeup Water—Emergency Makeup	B—Long-Term Core Cooling and Containment Integrity Maintain IC/PCCS pool inventory for passive core and containment cooling	22.5.6.3.2 22.5.6.3.3
3.7.1	2. SFP—Emergency Makeup Water	B—Long Term SFP Cooling Maintain SFP inventory for passive decay heat removal	22.5.6.3.2
3.7.2	FAPCS—Operating	C—Focused PRA (Uncertainty) Backup to passive safety system (i.e., to GDCCS) for core cooling (low-pressure injection) and containment heat removal	22.5.1.1.2 22.5.1.3.2

AC	TITLE	RTNSS CRITERION—MISSIONS	SER SECTION
3.7.3	FAPCS—Shutdown	C—Focused PRA (Uncertainty) Backup to passive safety system (i.e., to GDCS) for core cooling (low-pressure injection) and containment heat removal	22.5.1.1.2 22.5.1.3.2
3.7.4	Reactor Building HVAC Accident Exhaust Filtration	E—Adverse System Interactions Filters and exhausts reactor building CONAVS area to limit CRHA occupant doses for beyond-design-basis accidents	22.5.5.1 22.5.5.3
3.7.6	CRHAVS Post-72-Hour Long-Term Cooling		
3.7.6	CRHAVS AHUs	B—Long-Term Control Room Habitability	22.5.6.3.4 22.5.6.3.5
3.7.6	CRHAVS AHU Auxiliary Heaters and Coolers	B—Long-Term Cooling for Postaccident Monitoring Heat Loads	22.5.6.3.4 22.5.6.3.5
3.8.1	SDGs—Operating	C—Supports FAPCS Operation	22.5.1.1.2 22.5.1.3.2
3.8.2	SDGs—Shutdown	C—Supports FAPCS Operation	22.5.1.1.2 22.5.1.3.2
3.8.3	Ancillary DGs	B—Supports FPS Motor-Driven Pump, PCCS Vent Fans, CRHAVS AHUs, Emergency Lighting, Q-DCIS	22.5.6.3.4 22.5.6.3.5
4.1	BiMAC Device	D—Containment Performance Design feature that protects containment from core melt debris in conjunction with GDCS deluge function	22.5.2.3

DCD Tier 2, Revision 9, Table 19A-2, lists the SSCs that meet the RTNSS significance criteria, the criteria that each SSC satisfied, the proposed level of regulatory oversight, and any system the SSC supports. Typically, the Maintenance Rule governs any support SSCs that are not explicitly required by an ACLCO. By the definition of “availability” in Section 1.0 of the ACM, when a support system is not capable of performing its support function, the supported system is considered to be unavailable. The definition of “availability,” which is modeled on the Standard Technical Specification (STS) and the GTS definition of “operability,” is the following:

A system, subsystem, train, division, component, or device shall be AVAILABLE or have AVAILABILITY when it is capable of performing its specified risk informed function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train,

division, component, or device to perform its specified risk informed function(s) are also capable of performing their related support function(s).

The following table lists these support SSCs.

Table 22.5.9-2. RTNSS SSCs that Perform a Support Function.

SSC	SUPPORTED SSC	RTNSS SIGNIFICANCE CATEGORY	SUPPORTED AC
Emergency lighting	Postaccident monitoring instrumentation	B—Postaccident monitoring	LCO 3.3.3.2
Ancillary ac power buses	AC power distribution from ancillary DGs to plant loads	B—AC power distribution	All RTNSS systems requiring ancillary ac power
Ancillary DG fuel oil tank	Ancillary DGs	B—Supports ancillary DGs	3.8.3
Ancillary DG fuel oil transfer pump	Ancillary DGs	B—Supports ancillary DGs	3.8.3
Ancillary DG building HVAC	Ancillary DGs	B—Supports ancillary DGs	3.8.3
N-DCIS	DPS, FAPCS, and supporting equipment	C—Supports DPS, FAPCS, and supporting equipment	3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.5.1, 3.6.3, 3.7.1, 3.7.2, 3.7.3, 3.7.5, 3.7.6, 3.8.1, 3.8.2, 3.8.3
SDGs	FAPCS	C—Supports FAPCS operation	3.7.1, 3.7.2, 3.7.3
6.9-kilovolt PIP Buses	Plant loads associated with FAPCS	C—ac power distribution from SDGs to plant loads associated with FAPCS	3.3.1, 3.3.2, 3.3.3, 3.3.4, 3.5.1, 3.6.3, 3.7.1, 3.7.2, 3.7.3, 3.7.5, 3.7.6, 3.8.1, 3.8.2
SDG auxiliaries	SDGs	C—Supports SDGs	3.8.1, 3.8.2
RCCWS	SDGs and NICWS	C—Supports SDGs and NICWS	3.7.2, 3.7.3, 3.7.5, 3.7.6, 3.8.1, 3.8.2
NICWS	Building HVAC	C—Building HVAC	3.7.5, 3.7.6
PSWS	RCCWS	C—Supports RCCWS	3.7.5, 3.7.6, 3.8.1, 3.8.2

SSC	SUPPORTED SSC	RTNSS SIGNIFICANCE CATEGORY	SUPPORTED AC
Electrical building HVAC area cooling	PIP buses, N-DCIS for FAPCS	C—Supports PIP buses, N-DCIS for FAPCS	3.7.2, 3.7.3
Fuel building HVAC local cooling	FAPCS, N-DCIS for FAPCS	C—Supports FAPCS, N-DCIS for FAPCS	3.7.2, 3.7.3
Reactor building HVAC local cooling	N-DCIS for FAPCS	C—Supports N-DCIS for FAPCS	3.7.2, 3.7.3
Turbine building HVAC local cooling	FAPCS	C—Supports FAPCS	3.7.2, 3.7.3

22.5.9.2 Regulatory Criteria

The applicable criteria for establishing which RTNSS SSCs require TS are the four screening criteria specified in 10 CFR 50.36(c)(2)(ii) for establishing LCOs. RG 1.206, which describes the scope, criteria, and process used to determine RTNSS in the passive plant design, provides guidance to applicants in establishing appropriate regulatory oversight for RTNSS SSCs, including short-term ACs if necessary, as determined by risk significance.

22.5.9.3 Staff Evaluation

The ACM specifies ACs for RTNSS functions as completion times. The ACs are established to ensure that the availability of each function is consistent with the functional unavailability in the ESBWR PRA. The surveillance requirements are also established to provide an adequate level of support to ensure that component performance is consistent with the functional reliability in the ESBWR PRA. Support systems inherit the ACs of the systems they support. This approach is consistent with the process for establishing RTNSS described in RG 1.206 and summarized in Section 22.3.6 of this report. Therefore, the staff finds it acceptable. The ACs of RTNSS-important SSCs are formatted similarly to the GTS with availability requirements, applicability, required actions and completion times (if availability requirements are not met), surveillance requirements, and bases. There are no requirements to bring the plant to a safe-shutdown condition when availability requirements are not fulfilled and completion times for required actions are not met. The staff finds this acceptable because (1) these RTNSS-important nonsafety-related SSCs do not meet any of the regulatory criteria stated in 10 CFR 50.36(c)(2)(ii) for establishing TS LCOs, and (2) the ESBWR D-RAP, as described in DCD Tier 2, Revision 9, Section 17.4, includes these RTNSS-important SSCs, which will ensure that COL applicants monitor and control the availability and reliability of these SSCs in accordance with 10 CFR 50.65.

In RAI 22.5-22, the staff requested that GEH clarify the following ACs (as numbered in DCD Tier 2, Revision 5) to state the associated instrumentation functions and the number of required divisions:

- AC 3.3.1 (ARI)
- AC 3.3.2 (ATWS/SLC system actuation)
- AC 3.3.3 (FWRB)
- AC 3.3.5 (ADS inhibit)

- AC 3.5.1 (GDCS deluge function)

The staff also requested that the applicant describe, in the associated bases for these ACs, the minimum level of system degradation that corresponds to a function being unavailable and the number of divisions used to determine the test interval for each required division (or component) for AC surveillance requirements (e.g., logic system functional test) that specify a frequency of 24 months on a staggered test basis. RAI 22.5-22 was being tracked as an open item in the SER with open items.

In response to RAI 22.5-22, GEH deleted AC 3.3.5 and moved the ATWS/SLC inhibit of ADS function, which inhibits the SSLC/ESF actuation of ADS (GTS 3.3.5.2) under conditions indicative of an ATWS, to AC 3.3.2, "ATWS/SLC System Actuation," as Function 3. The applicant moved the DPS ADS inhibit function, which inhibits the diverse actuation of ADS by DPS (GTS 3.3.8.1), to AC 3.3.4 and renumbered the function as Function 8. The applicant also moved the RWCU/SDC system isolation ATWS/SLC function to AC 3.3.2 as Function 2. Grouping the ATWS/SLC functions of SLC actuation, RWCU/SDC isolation, and ADS inhibit in the same AC improved the presentation of the requirements for these functions because they are closely related to the initiation of the SLC system under conditions indicative of an ATWS. Therefore, the staff finds ACLCO 3.3.2 acceptable. The staff also believes that it is appropriate to group the DPS ADS inhibit function with the other RTNSS functions for DPS backup actuation functions for reactor scram, ECCS, ICS, and isolation functions in the renumbered AC 3.3.4. Therefore, the staff finds ACLCO 3.3.4 to be acceptable. These changes are reflected in DCD Tier 2, Revision 9.

The applicant stated that failure of components related to the subject AC functions would result in entry into Action A of the associated AC. This is a conservative approach to specifying action requirements and is acceptable. Consequently, adding a discussion to the AC bases regarding the various levels of degradation corresponding to the unavailability of an AC-required function is unnecessary; other sections of the DCD provide system design details. Therefore, the staff finds that this issue is resolved.

Regarding the request to identify the number of required divisions, the applicant explained that the ARI function and the FWRB function are actuated by nonsafety-related logic that is processed by the DPS. The DPS is a triple-redundant control system. The DPS is not a divisional instrumentation system. It is not powered by the four divisions of the safety-related dc and uninterruptible ac power distribution system. Even though the triple-redundant control systems have two or three separate nonsafety-related power sources, the action and surveillance requirements do not take advantage of any redundancies that may exist. Therefore, this issue is resolved for the ARI function of AC 3.3.1 and the FWRB function of AC 3.3.3.

The ATWS/SLC system actuation functions required by AC 3.3.2 are performed by safety-related logic processors in each of the four divisional reactor trip and isolation function (RTIF) cabinets. Although the safety-related ATWS/SLC actuation functions are based on a four-division instrumentation system, ACLCO 3.3.2 requires the function to be available. Therefore, failure of an ATWS/SLC function in any required actuation division (as explained below) would result in entry into AC 3.3.2, Action A. In DCD Tier 2, Revision 7, GEH further revised the bases to state the following:

There are ATWS mitigation logic processors in each of four divisional RTIF cabinets. The ATWS mitigation logic processors are separate and diverse from

RPS circuitry. Each ATWS mitigation logic processor uses discrete programmable logic devices for ATWS mitigation logic processing. The programmable logic devices provide voting logic, control logic, and time delays for evaluating the plant conditions for automatic initiation of SLC boron injection. Although there are four divisions of the ATWS/SLC platform for each Function, only two divisions are required for a Function to be considered AVAILABLE. The two required divisions are those divisions associated with the DC and Uninterruptible AC Electrical Power Distribution Divisions required by LCO 3.8.6, "Distribution Systems—Operating," and LCO 3.8.7, "Distribution Systems—Shutdown."

Requiring just two actuation divisions is acceptable because (1) only two divisions are required to cause actuation of the SLC system and related functions to mitigate an ATWS event and (2) the ATWS/SLC actuation logic is not required to withstand a single failure. Because ACLCO 3.3.2 requires just two divisions, the staff infers that ACSR 3.3.2.4, which calls for the performance of a logic system function test (LSFT) once every 24 months on a staggered test basis, requires performing an LSFT on each required division for each of the three functions once every 48 months. This is consistent with the resolution of staggered testing in GTS 3.3 as discussed in Sections 16.2.6.4.5 and 16.2.6.4.6 of the report, but contrary to the assertion in the applicant's response to RAI 22.5-22 that stated that the staggered testing for the LSFT is based on four divisions. In DCD Tier 2, Revision 7, GEH removed the allowance for staggered testing from the 24-month frequency for LSFT surveillance requirements because it lacked a technical basis. Since this change will require more frequent performance of the LSFT on each actuation division, the staff finds it acceptable. However, this change did not include the ACSR 3.3.2.4 staggered testing provision for the LSFT. The applicant corrected this oversight in DCD Tier 2, Revision 7. Also, with just two actuation divisions being required for each function, Condition A is appropriate because, with less than two divisions available, the affected function is unavailable. Therefore, the issue regarding the number of required divisions and LSFT staggered testing is resolved for the ATWS/SLC functions of AC 3.3.2. With regard to the staggered testing issue for the other ACSRs, the applicant stated the following in their response to RAI 22.5-22:

The functions specified by AC 3.3.1, AC 3.3.3, and AC 3.5.1 are processed by nonsafety-related instrumentation systems that are non-divisional.... Therefore, ACSR 3.3.1.3, ACSR 3.3.3.2, and ACSR 3.5.1.3 are revised to delete reference to divisions. The associated Frequencies are revised to delete "on a STAGGERED TEST BASIS." With this change, the associated Logic System Functional Tests will be performed at a Frequency of 24 months.

Based on the described changes, the staggered testing issue is resolved for the actuation functions of ARI, FWRB, and GDCS deluge.

In response to RAI 22.5-22, the applicant explained that the GDCS deluge function is executed in a pair of dedicated, nonsafety-related programmable logic controllers (PLCs) and a pair of dedicated, safety-related temperature switches. Both PLC outputs and both temperature switch outputs must operate to fire the squib initiator associated with each deluge valve. The GDCS deluge function logic is nondivisional. Therefore, the issue regarding the number of required divisions is resolved for the GDCS deluge function of AC 3.5.1.

In RAI 22.5-22 S01, the staff also requested that GEH further clarify the provisions proposed for AC 3.3.2. In its response, GEH reiterated its previous explanation that ACLCO 3.3.2 requires

just two divisions of each ATWS/SLC actuation function, removed the phrase “for each required SLC actuation function of the ATWS/SLC automatic actuation division” from ACSR 3.3.2.4 as inappropriate, and confirmed that ACSR 3.3.2.4 applies to all three ATWS/SLC required functions. In addition, GEH stated that ACM Table 3.3.2-1 does not include manual switches for ATWS ADS inhibit as part of Function 3 because they are not considered in the RTNSS evaluation or in the scope of the ACM. The staff finds these clarifications to be acceptable.

The applicant also clarified that two GDCS pools and six deluge squib valves perform the deluge function. This is consistent with the Level 2 ESBWR PRA success criterion for GDCS deluge valves. GEH revised ACLCO 3.5.1 and the associated bases to require 6 of the 12 deluge squib valves to be available. In addition, GEH stated that it will include all RTNSS components, including all 12 deluge valves, under the Maintenance Rule. The applicant also committed to including the deluge valves under the ESBWR D-RAP and the inservice test program. The staff finds these clarifications to be acceptable because they show that the ACs for the deluge squib valves are consistent with assumptions in the ESBWR PRA.

The applicant confirmed that AC action requirements may be exited based on an assessment that the degraded RTNSS function is still available. However, GEH does not intend that COL applicants apply the guidance of Regulatory Issue Summary 2005-20, Revision 1, “Revision to NRC Inspection Manual Part 9900 Technical Guidance, ‘Operability Determinations & Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety,’” dated April 16, 2008, regarding operability determinations for degraded equipment, to such availability assessments. Nevertheless, the staff finds this approach to resolving AC actions consistent with the operability determination guidance. Any determination that the component is available must have concluded that all applicable ACSRs are met. Further, since AC actions contain no unit shutdown requirements, continued operation with a degraded RTNSS function based on an availability assessment is not a significant risk to plant safety. Therefore, the staff finds the applicant’s response to be acceptable.

Based on the above clarifications and changes to the ACM, RAI 22.5-22 and the associated open item are resolved.

In RAI 22.5-23, the staff requested that the applicant explain why the ACs for the FAPCS (1) did not include an ACSR for the FAPCS pumps, which serve the low-pressure injection and suppression pool cooling functions, and (2) require only one FAPCS train to be available during operation, which is inconsistent with the applicant’s focused PRA that models the availability of two trains. RAI 22.5-23 was being tracked as an open item in the SER with open items.

In its response to RAI 22.5-23 and in DCD Tier 2, Revision 5, GEH revised AC 3.7.2, “FAPCS—Operating,” to require two FAPCS trains to be available in Modes 1, 2, 3, and 4. The staff finds this acceptable. In RAI 22.5-41, the staff repeated its question regarding ACSRs for the FAPCS pumps. In its response, GEH stated that, since the FAPCS pumps associated with low-pressure injection, suppression pool cooling, and alternate shutdown cooling (during Mode 5 and Mode 6) are normally in operation for SFP cooling, ACSRs for these pumps are unnecessary to demonstrate their availability. In addition, GEH added the FAPCS pumps to the list of FAPCS mechanical components in DCD, Tier 1, Revision 7, Table 2.6.2-1. The staff finds this response acceptable. Therefore, RAI 22.5-23 and the associated open item, as well as RAI 22.5-41, are resolved.

In RAI 22.5-24, the staff asked why (1) ACLCO 3.8.1, “Standby Diesel Generators—Operating,” specifies that only one standby DG needs to be available, which is inconsistent with the

applicant's focused ESBWR PRA that models the availability of two SDGs, and (2) the actions of AC 3.8.1 permit the standby DG to be unavailable for a period of 14 days, while AC 3.7.2 only allows the supported FAPCS train to be unavailable for 7 days. (In DCD Tier 2, Revision 5, GEH changed the completion time to restore a FAPCS train to available status to 14 days to be consistent with Action A of AC 3.8.1 and Action A of AC 3.8.2 for the SDGs.) RAI 22.5-24 was being tracked as an open item in the SER with open items.

In response to RAI 22.5-24, GEH stated that just one standby DG is needed during unit operation to support FAPCS and postaccident monitoring, but that two SDGs are needed during Modes 5 and 6 to support both RWCU/SDC trains for decay heat removal, since the ICS may not be available to remove decay heat in these modes. (GTS 3.5.5 requires the ICS to be operable in Mode 5 to back up the RWCU/SDC system, but requires the RCS to heat up to Mode 4 conditions to be effective.) GEH stated that "the risk significance is elevated during shutdown modes because the containment is open, thus any core damage event contributes directly to the large release frequency." To ensure that the SDGs are maintained available during refueling outages, GEH chose, in AC 3.8.2, "Standby Diesel Generators—Shutdown," a 24-hour completion time for Required Action B.1 to restore one standby DG to available status if both SDGs are unavailable.

In RAI 22.5-24 S01, the staff asked the applicant to revise AC 3.8.1 to be consistent with the availability and reliability assumptions in the PRA and require two SDGs to be available. In its response to RAI 22.5-24 S01 EH stated the following:

FAPCS meets RTNSS Criterion C, which addresses uncertainty in passive system performance. FAPCS provides active backup functions for coolant injection and suppression pool heat removal. The at-power focused PRA sensitivity study for RTNSS Criterion C assumes that one FAPCS train is capable of backing up these passive functions. Therefore, one FAPCS train and its supporting functions, including one standby DG, are assumed to be available for normal operations.

The staff found this reasoning acceptable. Nevertheless, in DCD Tier 2, Revision 5, GEH revised AC 3.7.2 to require two FAPCS trains to be available during unit operation. In the supplement, the staff asserted that the completion times to restore RTNSS components to available status should, in general, be based on reasonable repair times, since the ACM never requires a unit shutdown for failure to restore components to available status within the specified completion time. The staff also asked GEH in RAI 22.5-24 S01 to address this point. In response, GEH stated the following:

The PRA evaluates the functions satisfying the RTNSS criteria to determine their risk significance. Those functions with high risk significance are included in the TS. Those functions with low risk significance are included in the ACM. CDF and LRF are relatively insensitive to the availability of these low risk significant systems. As explained in DCD Tier 2 Revision 7 Section 19A, that is specifically why they are in the ACM rather than TS. To apply the same requirements as TS, then, would be inappropriate. Neither a unit shutdown requirement nor revisions to the completion time are necessary to provide reasonable assurance that the availability of low risk significant SSCs will be consistent with the availability assumed in the PRA.

The staff agrees that applying the same requirements as TS is not appropriate and accepts the applicant's reasoning. This resolved RAI 22.5-32, which raised the same issue. In the supplement, the staff also asked GEH to modify ACLCO 3.0.3 to include a requirement to assess and manage risk. In response, GEH added the following provision to ACLCO 3.0.3 to provide confirmation that there are no significant increases in risk during operation under ACLCO 3.0.3: "Assess and manage the risk of the resulting unit configuration." The staff finds this acceptable because it clearly states that risk must be assessed and managed.

Based on the above clarifications and changes to the ACM, RAI 22.5-24 and the associated open item are resolved.

In RAI 22.5-30, the staff questioned the lack of channel check and channel calibration ACSR in AC 3.5.1 for the drywell atmosphere and lower drywell basemat thermocouples. In its response, GEH indicated that it would add such channel check and channel calibration ACSR to AC 3.5.1. The staff has confirmed this addition in DCD Tier 2, Revision 7. Therefore, RAI 22.5-30 is resolved.

In RAI 22.5-31, the staff questioned the appropriateness of the frequency for performing reactor building HVAC accident exhaust filtration unit testing specified in ACSR 3.7.5.2. DCD Tier 2, Revision 5, Section 9.4.6.4 states, "The Reactor Building HVAC Purge Exhaust Filter components are periodically tested in accordance with Regulatory Guide 1.140, Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Normal Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants." The staff asked the applicant why it did not base the test frequency on RG 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," since the bases state that these filtration units are relied upon to provide "exhaust filtering efficiency to ensure that theoretical control room doses are not exceeded for certain beyond design-basis LOCAs." In its response, GEH stated, "Regulatory Guide (RG) 1.52 does not apply to testing these nonsafety-related units because they perform a beyond-design-basis function, which is not required to satisfy GDC 19 dose limits." Therefore, RAI 22.5-31 is resolved.

In RAI 22.5-33, the staff requested that GEH explain the basis for the following statements which appear in the bases for each AC:

The short-term ACs for this function, which are specified as Completion Times, are acceptable to ensure that the availability of this function is consistent with the functional availability in the ESBWR PRA. The surveillance requirements also provide an adequate level of support to ensure that component performance is consistent with the functional reliability in the ESBWR PRA.

In response, GEH stated the following:

The Bases statement about completion times and surveillance requirements being consistent with the PRA assumptions reflects the fact that the CDF and LRF are relatively insensitive to the unavailability of components identified in the RTNSS process. The statement is not intended to imply that there is some direct relational calculation used to derive availability and reliability requirements. The nonsafety-related systems meeting the RTNSS criteria that are LRO are included in the ACM. They have low risk significance, and thus, basing allowable outage times on risk significance would result in inordinately long allowable outage

times. As for support systems, the availability of support systems for a given ACM function is already required by the definition of availability under AC 1.1.

The staff finds this reasoning acceptable. In RAI 22.5-33, the staff also questioned the frequency of 24 hours specified for channel check in ACSR 3.3.4.1 and the frequency of 24 months specified in ACSR 3.3.5.2, "Channel Functional Test," because these frequencies are not consistent with the STS. The applicant changed these frequencies to 12 hours and 92 days, respectively, in DCD Tier 2 Revision 7. Therefore, RAI 22.5-33 is resolved.

In RAI 22.5-34, the staff questioned the use of the term "required" in several ACs. In response to RAI 22.5-34, GEH removed the word "required" from Condition A of AC 3.3.2 and AC 3.3.4, but stated that it was appropriate for Condition A of AC 3.7.1 because, as indicated in DCD Tier 2, Revision 5, Section 9.5.1.4, the ACLCO do not include redundant components (e.g., secondary diesel-driven and motor-driven fire pumps). Therefore, RAI 22.5-34 is resolved.

In RAI 22.5-35 the staff noted that DCD Tier 2, Section 19A.8.4.3, was not consistent with AC 3.3.5 in that it did not list the ADS inhibit function, which is specified in AC 3.3.5, Table 3.3.5-1, Function 7. In response to RAI 22.5-35, GEH revised DCD Tier 2, Section 19A.8.4.3, Revision 5, to include the DPS ADS inhibit function specified in AC 3.3.4, Function 8. Therefore, RAI 22.5-35 is resolved.

In RAI 22.5-36, the staff questioned the applicant's statement in DCD Tier 2, Revision 5, Section 19A.8.4.10 indicating that use of the PARs to redistribute noncondensable gas between the wetwell and drywell reduces overall containment pressure. In response to RAI 22.5-36, GEH revised DCD Tier 2, Section 19A.8.4.10, to replace "overall containment pressure" with "containment pressure" and to clarify that the PCCS vent fans (AC 3.6.3), by transferring noncondensable gases to the drywell, reduce the pressure in the wetwell airspace that is attributable to long-term accumulation of noncondensable gases. GEH stated the following:

[R]edistributing the non-condensable gases from the wetwell air space to the drywell reduces the pressure in the wetwell airspace. The PARs (AC 3.6.2) recombine the hydrogen and oxygen that accumulate in the wetwell air space and drywell. The combination of the PARs and the PCCS vent fans maintains acceptable containment pressure.

The staff agrees that pressure in the wetwell air space can be reduced using the PARS and PCCS vent fans as described and that the changes to the DCD Tier 2, clarify the original statements in an acceptable way. Therefore, RAI 22.5-36 is resolved.

In RAI 22.5-37, the staff requested that the applicant confirm that instrumentation settings for Availability Control Manual Section 3.3 instrumentation functions are controlled by GTS 5.5.11, "Setpoint Control Program (SCP)." In response to RAI 22.5-37, GEH stated that GTS 5.5.11, "Setpoint Control Program," does not control the instrumentation settings for the ACM. As discussed in the GEH response to RAI 7.1-86 S01, the SCP-specified setpoint methodology only applies to safety-related and TS instrumentation settings. The calibration of nonsafety-related instrumentation is handled by plant procedures, which are controlled as described in DCD Tier 2, Revision 5, Section 13.5. Therefore, RAI 22.5-37 is resolved.

In RAI 22.5-38, the staff questioned the completeness of the Bases for selected ACs in comparison to the Bases for most other ACs. In response to RAI 22.5-38, GEH added references to the appropriate DCD sections in the bases for the DPS functions of AC 3.3.4 and

added a discussion of the DPS function of SLC system diverse actuation on a LOCA signal in the bases for AC 3.3.4. Therefore, RAI 22.5-38 is resolved.

In RAI 22.5-39 the staff requested that the applicant explain why ACSR 3.5.1.4 contains the note, "Squib actuation may be excluded," or remove the note and describe how the deluge line flow paths are verified to not be obstructed. In response to RAI 22.5-39, GEH added the following to DCD Tier 2: (1) ACSR 3.5.1.4 to verify once every 24 months that required deluge valves actuate on an actual or simulated automatic initiation signal, and (2) ACSR 3.5.1.6 to verify once every 24 months on a staggered test basis the flowpath for each deluge line is not obstructed. Therefore, RAI 22.5-39 is resolved.

In RAI 22.5-42, the staff requested that GEH revise AC 3.7.1 to provide a surveillance requirement for the electric fire pump. In response to RAI 22.5-42, GEH stated that an ACSR for the motor-driven fire pump in AC 3.7.1 is not necessary because the pump is already tested in accordance with National Fire Protection Association (NFPA) 20, "Standard for the Installation of Stationary Pumps for Fire Protection," as discussed in DCD Tier 2, Revision 5, Table 9.5-1. The staff finds this to be an acceptable basis for excluding the ACSR in AC 3.7.1. Therefore RAI 22.5-42 is resolved.

In RAI 22.5-45, the staff questioned the lack of surveillances for the standby DGs in the ACM. In response to RAI 22.5-45, GEH added (1) ACSR 3.8.1.3 and ACSR 3.8.2.3 to verify once every 92 days that the fuel oil transfer system operates to transfer fuel oil from the storage tank to the required standby DG day tank, (2) ACSR 3.8.1.4 and ACSR 3.8.2.4 to verify once every 24 months that the required standby DG starts and achieves rated speed and voltage upon receipt of an under-voltage signal and sequences its designed loads while maintaining voltage and frequency within design limits, and (3) ACSR 3.8.1.5 and ACSR 3.8.2.5 to verify once every 24 months that the required standby DG starts and operates at rated load for 24 hours or longer. GEH also revised the bases for AC 3.8.1 and 3.8.2 by changing the following statement as indicated: "DG starts required by ACSRs may be preceded by an engine pre-lube period prior to starting and warm-up period prior to loading to minimize wear and tear on the DGs during testing." These ACSRs are consistent with typical surveillance requirements for DGs in operating reactors and are therefore acceptable. Therefore, RAI 22.5-45 is resolved.

In RAI 16.2-62 S01 and S02, the staff questioned the lack of ACs for the qualified offsite ac power circuits and the onsite ac power distribution circuits. In its responses, GEH stated that its RTNSS analysis had concluded that the offsite circuits do not meet the RTNSS significance criteria and that the onsite ac circuits (PIP buses, ancillary buses) satisfied RTNSS criteria in support roles for other RTNSS equipment. Based on the above evaluation of ESBWR nonsafety-related systems against the RTNSS criteria, the staff concludes that the applicant's response is acceptable. Therefore, RAI 16.2-62 is resolved.

22.5.9.4 Conclusions

Based on the preceding evaluations and RAI resolutions, the ACM is acceptable.

22.5.10 Staff Conclusions

The staff has reviewed the applicant's implementation of the RTNSS process described in DCD Tier 2, Revision 9, Section 19A, and finds that the applicant's implementation of this process satisfies the scope, criteria, and process described in SECY-94-084, SECY-94-132, and

RG 1.206 and summarized in Sections 22.2 and 22.3 of this report. Therefore, the staff finds the applicant's implementation to be acceptable.

23.0 REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The Advisory Committee on Reactor Safeguards (ACRS) has completed its review of the economic simplified boiling-water reactor (ESBWR) standard design. The ACRS Subcommittee on ESBWR met with representatives from GE-Hitachi Nuclear Energy and the U.S. Nuclear Regulatory Commission (NRC) staff on several occasions to discuss the ESBWR design.

On the basis of its reviews, the ACRS issued interim letter reports, dated November 20, 2007, March 20, 2008, May 23, 2008, July 21, 2008, October 29, 2008, and December 22, 2008. The staff responded to the interim letter reports in its letters dated February 1, 2008, April 24, 2008, July 8, 2008, August 15, 2008, December 2, 2008, and February 13, 2009, as well as during related meetings with the ACRS. At the 576th meeting of the ACRS, the full Committee considered the GE-Hitachi Nuclear Energy application for certification of the ESBWR standard design, and issued its final letter report to the NRC Chairman on October 20, 2010. That letter report is included as Appendix F to this report. In addition, the attachment to that letter report provides a chronology of the related ACRS reviews.

In its final letter report dated October 20, 2010, the ACRS concluded that the ESBWR design is robust and there is reasonable assurance that it can be built and operated without undue risk to the health and safety of the public.

24.0 CONCLUSIONS

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 52.48, the staff of the U.S. Nuclear Regulatory Commission (NRC) reviewed the economic simplified boiling-water reactor (ESBWR) design control document, probabilistic risk assessment, and Tier 1 information in accordance with the standards set forth in the following:

- 10 CFR Part 20, “Standards for Protection Against Radiation”
- 10 CFR Part 50, “Domestic Licensing of Production and Utilization Facilities” and its appendices
- 10 CFR Part 73, “Physical Protection of Plants and Materials”
- 10 CFR Part 100, “Reactor Site Criteria”

as they apply to applications for construction permits and operating licenses for nuclear power plants, as they are applicable and technically relevant to the ESBWR standard design, and as modified by the exemptions identified in Section 1.8 of this report. On the basis of its evaluation and independent analyses as discussed in this report, the staff concludes that GE-Hitachi Nuclear Energy’s application for design certification meets these requirements. Appendix F to this report includes a copy of the related report by the NRC’s Advisory Committee on Reactor Safeguards, as required by 10 CFR 52.53.

The staff also concludes that issuance of a final design approval, in accordance with 10 CFR Part 52, Subpart E, will not be inimical to either the common defense and security or the health and safety of the public. Pursuant to 10 CFR 50.33(f), the financial qualifications of an applicant for construction permit, operating license, or combined license (COL) will be addressed during the review of an application that references the ESBWR standard design. Similarly, the indemnity requirements of 10 CFR Part 140, “Financial Protection Requirements and Indemnity Agreements,” will be addressed in the operating license or COL review.

A final design approval, issued on the basis of this final safety evaluation report, does not constitute a commitment to issue a permit, design certification, or license, and does not in any way affect the authority of the Commission, the Atomic Safety and Licensing Board Panel, and other presiding officers in any proceeding under 10 CFR Part 2, “Rules of Practice for Domestic Licensing Proceedings and Issuance of Orders.”

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10. SUPPLEMENTARY NOTES

11. ABSTRACT (200 words or less)

This final safety evaluation report documents the technical review of General Electric-Hitachi's (GEH's) Economic Simplified Boiling-Water Reactor (ESBWR) design certification. GEH submitted its application for the ESBWR design on August 24, 2005, in accordance with Subpart B, "Standard Design Certifications," of 10 CFR Part 52. The NRC formally docketed the application for design certification (Docket No. 52-010) on December 1, 2005. The ESBWR design is a boiling-water reactor (BWR) rated up to 4,500 megawatts thermal (MWt) and has a rated gross electrical power output of 1,594 megawatts electric (MWe). The ESBWR is a direct-cycle, natural circulation BWR that relies on passive systems to perform safety functions credited in the design basis for 72 hours following an initiating event. After 72 hours, non-safety systems, either passive or active, replenish the passive systems in order to keep them operating or perform post-accident recovery functions directly. The ESBWR design also uses nonsafety-related active systems to provide defense-in-depth capabilities for key safety functions provided by passive systems. The ESBWR standard design includes a reactor building that surrounds the containment, as well as buildings dedicated exclusively or primarily to housing related systems and equipment. On the basis of its evaluation and independent analyses, as set forth in this report, the NRC staff concludes that GEH's application for design certification meets the requirements of 10 CFR Part 52, Subpart B, that are applicable and technically relevant to the ESBWR design. Appendix F includes a copy of the report by the Advisory Committee on Reactor Safeguards, as required by 10 CFR 52.53.

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