UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

September 23, 2016

Mr. Robert Coffey
Site Vice President
NextEra Energy Point Beach, LLC
6610 Nuclear Road
Two Rivers, WI 54241-9516

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 – SAFETY EVALUATION REGARDING IMPLEMENTATION OF MITIGATING STRATEGIES AND RELIABLE SPENT FUEL POOL INSTRUMENTATION RELATED TO ORDERS EA-12-049 AND EA-12-051 (CAC NOS. MF0725, MF0726, MF0729, AND MF0730)

Dear Mr. Coffey:

On March 12, 2012, the U.S. Nuclear Regulatory Commission (NRC) issued Order EA-12-049, "Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond Design-Basis External Events" and Order EA-12-051, "Order to Modify Licenses With Regard To Reliable Spent Fuel Pool Instrumentation," (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML12054A736 and ML12054A679, respectively). The orders require holders of operating reactor licenses and construction permits issued under Title 10 of the *Code of Federal Regulations* Part 50 to modify the plants to provide additional capabilities and defense-in-depth for responding to beyond-design-basis external events, and to submit for review Overall Integrated Plans (OIPs) that describe how compliance with the requirements of Attachment 2 of each order will be achieved.

By letter dated February 22, 2013 (ADAMS Accession No. ML13053A401), NextEra Energy Point Beach, LLC (NextEra, the licensee) submitted its OIP for Point Beach Nuclear Plant, Units 1 and 2 (Point Beach) in response to Order EA-12-049. At 6 month intervals following the submittal of the OIP, the licensee submitted reports on its progress in complying with Order EA-12-049. These reports were required by the order, and are listed in the attached safety evaluation. By letter dated August 28, 2013 (ADAMS Accession No. ML13234A503), the NRC notified all licensees and construction permit holders that the staff is conducting audits of their responses to Order EA-12-049 in accordance with NRC Office of Nuclear Reactor Regulation (NRR) Office Instruction LIC-111, "Regulatory Audits" (ADAMS Accession No. ML082900195). By letters dated January 27, 2014 (ADAMS Accession No. ML13338A510), and August 27, 2015 (ADAMS Accession No. ML15208A027), the NRC issued an Interim Staff Evaluation (ISE) and audit report, respectively, on the licensee's progress. By letter dated December 16, 2015 (ADAMS Accession No. ML15350A085), NextEra submitted a compliance letter and Final Integrated Plan (FIP) in response to Order EA-12-049. The compliance letter stated that the licensee had achieved full compliance with Order EA-12-049.

By letter dated February 22, 2013 (ADAMS Accession No. ML13053A399), NextEra submitted its OIP for Point Beach in response to Order EA-12-051. At 6 month intervals following the submittal of the OIP, the licensee submitted reports on its progress in complying with Order EA-12-051. These reports were required by the order, and are listed in the attached safety evaluation. By letter dated November 18, 2013 (ADAMS Accession No. ML13309A011), the NRC staff issued an ISE and request for information on the licensee's progress. By letter dated March 26, 2014 (ADAMS Accession No. ML14083A620), the NRC notified all licensees and construction permit holders that the staff is conducting audits of their responses to Order EA-12-051 in accordance with NRC NRR Office Instruction LIC-111, similar to the process used for Order EA-12-049. By letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), NextEra submitted a compliance letter in response to Order EA-12-051. The compliance letter stated that the licensee had achieved full compliance with Order EA-12-051.

The enclosed safety evaluation provides the results of the NRC staff's review of NextEra's strategies for Point Beach. The intent of the safety evaluation is to inform NextEra on whether or not its integrated plans, if implemented as described, appear to adequately address the requirements of Orders EA-12-049 and EA-12-051. The staff will evaluate implementation of the plans through inspection, using Temporary Instruction 191, "Implementation of Mitigation Strategies and Spent Fuel Pool Instrumentation Orders and Emergency Preparedness Communications/Staffing/ Multi-Unit Dose Assessment Plans" (ADAMS Accession No. ML15257A188). This inspection will be conducted in accordance with the NRC's inspection schedule for the plant.

If you have any questions, please contact Jason Paige, Orders Management Branch, Point Beach Project Manager, at Jason.Paige@nrc.gov.

Sincerely,

Mandy K Halter

Mandy Halter, Acting Chief
Orders Management Branch
Japan Lessons-Learned Division
Office of Nuclear Reactor Regulation

Docket Nos.: 50-266 and 50-301

Enclosure:
Safety Evaluation

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO ORDERS EA-12-049 AND EA-12-051

NEXTERA ENERGY POINT BEACH, LLC

POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

DOCKET NOS. 50-266 AND 50-301

1.0 INTRODUCTION

The earthquake and tsunami at the Fukushima Dai-ichi nuclear power plant in March 2011, highlighted the possibility that extreme natural phenomena could challenge the prevention, mitigation and emergency preparedness defense-in-depth layers already in place in nuclear power plants in the United States. At Fukushima, limitations in time and unpredictable conditions associated with the accident significantly challenged attempts by the responders to preclude core damage and containment failure. During the events in Fukushima, the challenges faced by the operators were beyond any faced previously at a commercial nuclear reactor and beyond the anticipated design-basis of the plants. The U.S. Nuclear Regulatory Commission (NRC) determined that additional requirements needed to be imposed at U.S. commercial power reactors to mitigate such beyond-design-basis external events (BDBEEs).

On March 12, 2012, the NRC issued Order EA-12-049, "Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events" (Agencywide Documents Access and Management System (ADAMS) Accession No. ML12054A736). This order directed licensees to develop, implement, and maintain guidance and strategies to maintain or restore core cooling, containment, and spent fuel pool (SFP) cooling capabilities in the event of a BDBEE. Order EA-12-049 applies to all power reactor licensees and all holders of construction permits for power reactors.

On March 12, 2012, the NRC also issued Order EA-12-051, "Order Modifying Licenses With Regard to Reliable Spent Fuel Pool Instrumentation" (ADAMS Accession No. ML12054A679). This order directed licensees to install reliable SFP level instrumentation with a primary channel and a backup channel, and with independent power supplies that are independent of the plant alternating current (ac) and direct current (dc) power distribution systems. Order EA-12-051 applies to all power reactor licensees and all holders of construction permits for power reactors.

2.0 REGULATORY EVALUATION

Following the events at the Fukushima Dai-ichi nuclear power plant on March 11, 2011, the NRC established a senior-level agency task force referred to as the Near-Term Task Force

(NTTF). The NTTF was tasked with conducting a systematic and methodical review of the NRC regulations and processes and determining if the agency should make additional improvements to these programs in light of the events at Fukushima Dai-ichi. As a result of this review, the NTTF developed a comprehensive set of recommendations, documented in SECY-11-0093, "Near-Term Report and Recommendations for Agency Actions Following the Events in Japan," dated July 12, 2011 (ADAMS Accession No. ML11186A950). Following interactions with stakeholders, these recommendations were enhanced by the NRC staff and presented to the Commission.

On February 17, 2012, the NRC staff provided SECY-12-0025, "Proposed Orders and Requests for Information in Response to Lessons Learned from Japan's March 11, 2011, Great Tohoku Earthquake and Tsunami," (ADAMS Accession No. ML12039A103) to the Commission. This paper included a proposal to order licensees to implement enhanced BDBEE mitigation strategies. As directed by the Commission in Staff Requirements Memorandum (SRM)-SECY-12-0025 (ADAMS Accession No. ML120690347), the NRC staff issued Orders EA-12-049 and EA-12-051.

2.1 Order EA-12-049

Order EA-12-049, Attachment 2 (ADAMS Accession No. ML12054A736), requires that operating power reactor licensees and construction permit holders use a three-phase approach for mitigating BDBEEs. The initial phase requires the use of installed equipment and resources to maintain or restore core cooling, containment and SFP cooling capabilities. The transition phase requires providing sufficient, portable, onsite equipment and consumables to maintain or restore these functions until they can be accomplished with resources brought from off site. The final phase requires obtaining sufficient offsite resources to sustain those functions indefinitely. Specific requirements of the order are listed below:

1) Licensees or construction permit (CP) holders shall develop, implement, and maintain guidance and strategies to maintain or restore core cooling, containment, and SFP cooling capabilities following a beyond-design-basis external event.

2) These strategies must be capable of mitigating a simultaneous loss of all alternating current (ac) power and loss of normal access to the ultimate heat sink [UHS] and have adequate capacity to address challenges to core cooling, containment, and SFP cooling capabilities at all units on a site subject to this Order.

3) Licensees or CP holders must provide reasonable protection for the associated equipment from external events. Such protection must demonstrate that there is adequate capacity to address challenges to core cooling, containment, and SFP cooling capabilities at all units on a site subject to this Order.

4) Licensees or CP holders must be capable of implementing the strategies in all modes of operation.

5) Full compliance shall include procedures, guidance, training, and acquisition, staging, or installing of equipment needed for the strategies.

On December 10, 2015, following submittals and discussions in public meetings with NRC staff, the Nuclear Energy Institute (NEI) submitted document NEI 12-06, Revision 2, "Diverse and Flexible Coping Strategies (FLEX) Implementation Guide" (ADAMS Accession No. ML16005A625), to the NRC to provide revised specifications for an industry-developed methodology for the development, implementation, and maintenance of guidance and strategies in response to the Mitigation Strategies order. The NRC staff reviewed NEI 12-06, Revision 2, and on January 22, 2016, issued Japan Lessons-Learned Directorate (JLD) Interim Staff Guidance (ISG) JLD-ISG-2012-01, Revision 1, "Compliance with Order EA-12-049, Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events" (ADAMS Accession No. ML15357A163), endorsing NEI 12-06, Revision 2, with exceptions, additions, and clarifications, as an acceptable means of meeting the requirements of Order EA-12-049, and published a notice of its availability in the *Federal Register* (81 FR 10283).

2.2 Order EA-12-051

Order EA-12-051, Attachment 2 (ADAMS Accession No. ML12054A679), requires that operating power reactor licensees and construction permit holders install reliable SFP level instrumentation. Specific requirements of the order are listed below:

> All licensees identified in Attachment 1 to the order shall have a reliable indication of the water level in associated spent fuel storage pools capable of supporting identification of the following pool water level conditions by trained personnel: (1) level that is adequate to support operation of the normal fuel pool cooling system, (2) level that is adequate to provide substantial radiation shielding for a person standing on the spent fuel pool operating deck, and (3) level where fuel remains covered and actions to implement make-up water addition should no longer be deferred.
>
> 1. The spent fuel pool level instrumentation shall include the following design features:
>
> 1.1 Instruments: The instrumentation shall consist of a permanent, fixed primary instrument channel and a backup instrument channel. The backup instrument channel may be fixed or portable. Portable instruments shall have capabilities that enhance the ability of trained personnel to monitor spent fuel pool water level under conditions that restrict direct personnel access to the pool, such as partial structural damage, high radiation levels, or heat and humidity from a boiling pool.
>
> 1.2 Arrangement: The spent fuel pool level instrument channels shall be arranged in a manner that provides reasonable protection of the level indication function against missiles that may result from damage to the structure over the spent fuel pool. This protection may be provided by locating the primary instrument channel and fixed portions of the backup

instrument channel, if applicable, to maintain instrument channel separation within the spent fuel pool area, and to utilize inherent shielding from missiles provided by existing recesses and corners in the spent fuel pool structure.

1.3 Mounting: Installed instrument channel equipment within the spent fuel pool shall be mounted to retain its design configuration during and following the maximum seismic ground motion considered in the design of the spent fuel pool structure.

1.4 Qualification: The primary and backup instrument channels shall be reliable at temperature, humidity, and radiation levels consistent with the spent fuel pool water at saturation conditions for an extended period. This reliability shall be established through use of an augmented quality assurance process (e.g., a process similar to that applied to the site fire protection program).

1.5 Independence: The primary instrument channel shall be independent of the backup instrument channel.

1.6 Power supplies: Permanently installed instrumentation channels shall each be powered by a separate power supply. Permanently installed and portable instrumentation channels shall provide for power connections from sources independent of the plant ac and dc power distribution systems, such as portable generators or replaceable batteries. Onsite generators used as an alternate power source and replaceable batteries used for instrument channel power shall have sufficient capacity to maintain the level indication function until offsite resource availability is reasonably assured.

1.7 Accuracy: The instrument channels shall maintain their designed accuracy following a power interruption or change in power source without recalibration.

1.8 Testing: The instrument channel design shall provide for routine testing and calibration.

1.9 Display: Trained personnel shall be able to monitor the spent fuel pool water level from the control room, alternate shutdown panel, or other appropriate and accessible location. The display shall provide on-demand or continuous indication of spent fuel pool water level.

2. The spent fuel pool instrumentation shall be maintained available and reliable through appropriate development and implementation of the following programs:

2.1 Training: Personnel shall be trained in the use and the provision of alternate power to the primary and backup instrument channels.

2.2 Procedures: Procedures shall be established and maintained for the testing, calibration, and use of the primary and backup spent fuel pool instrument channels.

2.3 Testing and Calibration: Processes shall be established and maintained for scheduling and implementing necessary testing and calibration of the primary and backup spent fuel pool level instrument channels to maintain the instrument channels at the design accuracy.

On August 24, 2012, following several NEI submittals and discussions in public meetings with NRC staff, the NEI submitted document NEI 12-02, "Industry Guidance for Compliance With NRC Order EA-12-051, To Modify Licenses With Regard to Reliable Spent Fuel Pool Instrumentation," Revision 1 (ADAMS Accession No. ML12240A307), to the NRC to provide specifications for an industry-developed methodology for compliance with Order EA-12-051. On August 29, 2012, the NRC staff issued its final version of JLD-ISG-2012-03, "Compliance with Order EA-12-051, Reliable Spent Fuel Pool Instrumentation" (ADAMS Accession No. ML12221A339), endorsing NEI 12-02, Revision 1, as an acceptable means of meeting the requirements of Order EA-12-051 with certain clarifications and exceptions, and published a notice of its availability in the *Federal Register* (77 FR 55232).

3.0 TECHNICAL EVALUATION OF ORDER EA-12-049

By letter dated February 22, 2013 (ADAMS Accession No. ML13053A401), NextEra Energy Point Beach, LLC (NextEra, the licensee) submitted its Overall Integrated Plan (OIP) for Point Beach Nuclear Plant, Units 1 and 2 (Point Beach) in response to Order EA-12-049. By letters dated August 28, 2013 (ADAMS Accession No. ML13241A203), February 28, 2014 (ADAMS Accesison No. ML14062A073), August 28, 2014 (ADAMS Accession No. ML14241A266), February 24, 2015 (ADAMS Accesison No. ML15050A487), and August 28, 2015 (ADAMS Accession No. ML15240A028), the licensee submitted 6-month updates to the OIP. By letter dated August 28, 2013 (ADAMS Accession No. ML13234A503), the NRC notified all licensees and construction permit holders that the staff is conducting audits of their responses to Order EA-12-049 in accordance with NRC Office of Nuclear Reactor Regulation (NRR) Office Instruction LIC-111, "Regulatory Audits" (ADAMS Accession No. ML082900195). By letters dated January 27, 2014 (ADAMS Accession No. ML13338A510), and August 27, 2015 (ADAMS Accession No. ML15208A027), the NRC issued an Interim Staff Evaluation (ISE) and an audit report on the licensee's progress. By letter dated December 16, 2015 (ADAMS Accession No. ML15350A085), the licensee reported that full compliance with the requirements of Order EA-12-049 was achieved, and submitted a Final Integrated Plan (FIP).

3.1 Overall Mitigation Strategy

Attachment 2 to Order EA-12-049 describes the three-phase approach required for mitigating BDBEEs in order to maintain or restore core cooling, containment, and SFP cooling capabilities. The phases consist of an initial phase (Phase 1) using installed equipment and resources, followed by a transition phase (Phase 2) in which portable onsite equipment is placed in service, and a final phase (Phase 3) in which offsite resources may be placed in service. The timing of when to transition to the next phase is determined by plant-specific analyses.

While the initiating event is undefined, it is assumed to result in an extended loss of alterating current (ac) power (ELAP) with a loss of normal access to the ultimate heat sink (UHS). Thus, the ELAP with loss of normal access to the UHS is used as a surrogate for a BDBEE. The initial conditions and assumptions for the analyses are stated in NEI 12-06, Section 3.2.1, and include the following:

1. The reactor is assumed to have safely shut down with all rods inserted (subcritical).
2. The dc [direct current] power supplied by the plant batteries is initially available, as is the ac power from inverters supplied by those batteries; however, over time the batteries may be depleted.
3. There is no core damage initially.
4. There is no assumption of any concurrent event.
5. Because the loss of ac power presupposes random failures of safety-related equipment (emergency power sources), there is no requirement to consider further random failures.

Point Beach is a Westinghouse pressurized-water reactor (PWR) with a dry ambient pressure containment. The licensee's three-phase approach to mitigate a postulated ELAP event, as described in the FIP, is summarized below.

At the onset of an ELAP both reactors are assumed to trip from full power. The reactor coolant pumps (RCPs) coast down and flow in the reactor coolant system (RCS) transitions to natural circulation. Operators will take prompt actions to minimize RCS inventory losses by isolating potential RCS letdown paths. Decay heat is removed by steaming to atmosphere from the steam generators (SGs) through the atmospheric dump valves (ADVs) or main steam safety valves (MSSVs), and makeup to the SGs is initially provided by the turbine-driven auxiliary feedwater (TDAFW) pump taking suction from the condensate storage tank (CST). Subsequently, the operators would begin a controlled cooldown and depressurization of the RCS by manually operating the SG ADVs. The SGs would be depressurized in a controlled manner to about 320 pounds per square inch gage (psig) over a period of several hours and then maintained at this pressure while the operators borate the RCS. Depressurizing the SGs reduces RCS temperature and pressure. Assuming both SGs are available, symmetric cooldown of the RCS would begin approximately 12 hours after the initiating event (concurrent with RCS boration). If one SG is not available (i.e., if an ADV has been damaged) operators would commence an asymmetric cooldown 15 hours after the initiating event, after the completion of RCS boration, which would begin at 8 hours into the event. The worst case asymmetric event is initiated by a sheared off MSSV/ADV and the reduction in RCS temperature will result in inventory contraction in the RCS, with the result that the pressurizer would drain and a steam void would form in the reactor vessel upper head. The RCS leakage, particularly from the RCP seals, would also contribute to the decrease in RCS liquid volume. However, during the cooldown RCS pressure should drop below the safety injection (SI) accumulator pressure and the injection of some quantity of borated water into the RCS from the accumulators would then occur.

The water supply for the TDAFW pump is initially from the CST. The CST will provide a minimum of 1 hour and 53 minutes of RCS decay heat removal. Prior to depletion of the CST, operators will align the installed diesel driven fire pump (DDFP) to take suction from the SW pump bay in the CWPH.

Operators will ultimately transition the SG water supply from the TDAFW pump to portable FLEX pumps using water from the Service Water (SW) pump bay in the Circulating Water Pump House (CWPH) and discharge to the suction of the TDAFWP.

The operators will perform dc bus load stripping within the initial 2 hours following event initiation to ensure safety-related battery life is extended up to 10 hours. Following dc load stripping and prior to battery depletion, one 404-kilowatt (kW), 480 volt alternating current (Vac) FLEX portable diesel generator (DG) will be deployed from a FLEX storage building (FSB) to supply power to both units. The portable generator will be used to repower essential battery chargers within 8 hours of ELAP initiation, as well as repowering the SI accumulator isolation valves.

The RCS makeup and boration will be initiated within 12 hours of the ELAP to ensure that natural circulation, reactivity control, and boron mixing is maintained in the RCS. Operators will provide reactor coolant makeup using portable FLEX high-pressure diesel-driven pumps, one per unit, to deliver water drawn from a FLEX connection on each refueling water storage tank (RWST) drain line. There is one RWST per unit. Borated water from the RWST will be injected into the RCS via the chemical volume and control system (CVCS) charging pump discharge drain line valve on either the "A" or "B" loop. In addition, during Modes 5 and 6, hoses can be routed from the Mode 5/6 RCS makeup pump(s) discharge to the RHR system FLEX connections.

In addition, a National Strategic Alliance of FLEX Emergency Response (SAFER) Response Center (NSRC) will provide high capacity pumps and large turbine-driven DGs that will be used to restore shutdown cooling (SDC), including the component cooling water (CCW) and RHR pumps to cool the cores in the long term. There are two NSRCs in the United States.

As discussed in the cooldown timeline, the licensee expects to further depressurize the SGs in order to further reduce RCS temperature and pressure. In addition, as noted in the FIP, by approximately 3 days into the event, the licensee expects to use FLEX equipment from offsite response centers to restore the RHR system and supporting equipment, the operation of which would allow RCS temperature to be reduced below 200 degrees Fahrenheit (°F). Prior to undertaking the additional cooling and depressurization of the RCS, operators would need to perform a number of supporting actions including injecting additional boric acid into the RCS to avoid the potential for recriticality and isolating the accumulators using electrical power from FLEX generators to avoid the potential for excessive accumulator injection to the point that the nitrogen cover gas could enter the RCS.

Point Beach has one SFP shared by both units and is located in the Primary Auxiliary Building (PAB). Upon initiation of the ELAP event, the SFP will heat up due to the unavailability of the normal cooling system. The licensee has calculated that boiling could start as soon as 7 hours after the start of the event. To maintain SFP cooling capabilities, the licensee determined that it would take approximately 71 hours for SFP water level to boil down to 6 inches above the fuel. Makeup water would be provided using either a manifold that allows the FLEX portable diesel-driven steam generator (PDSG) pump to inject flow to the SFP while also providing flow to the SGs or use the portable diesel-driven low pressure (PDLP) pump to provide SFP spray. These FLEX pumps (PDSG or PDLP) will draw raw water from the CWPH SW pump bay, forebay (directly or via the B.5.b standpipe) or direct draft from Lake Michigan. Ventilation of the generated steam is accomplished by opening the PAB truck access doors and personnel doors, as necessary, based on conditions.

For Phases 1 and 2, the licensee's calculations demonstrate that no actions are required to maintain containment pressure below design limits for 48 hours. In Phase 2, a PDLP pump will supply water to the Containment Spray (CS) system, if containment conditions warrant. During Phase 3, containment cooling and depressurization would be accomplished by restoring power to the containment cooling fans and cooling water flow to the containment fan coolers. The containment cooling fan would be powered by a 4160 Vac combustion turbine-driven DG supplied by the NSRC.

Below are specific details on the licensee's strategies to restore or maintain core cooling, containment, and SFP cooling capabilities in the event of a BDBEE, and the results of the staff's review of these strategies. The NRC staff evaluated the licensee's strategies against the endorsed NEI 12-06, Revision 2, guidance.

3.2 Reactor Core Cooling Strategies

In accordance with Order EA-12-049, licensees are required to maintain or restore cooling to the reactor core in the event of an ELAP concurrent with a LUHS. Although the ELAP results in an immediate trip of the reactor, sufficient core cooling must be provided to account for fission product decay and other sources of residual heat. Consistent with endorsed guidance from NEI 12-06, Phase 1 of the licensee's core cooling strategy credits installed equipment (other than that presumed lost to the ELAP/LUHS) that is robust in accordance with the guidance in NEI 12-06. In Phase 2, robust installed equipment is supplemented by onsite FLEX equipment, which is used to cool the core either directly (e.g., pumps and hoses) or indirectly (e.g., FLEX electrical generators and cables repowering robust installed equipment). The equipment available onsite for Phases 1 and 2 is further supplemented in Phase 3 by equipment transported from the NSRCs.

To adequately cool the reactor core under ELAP conditions, two fundamental physical requirements exist: (1) a heat sink is necessary to accept the heat transferred from the reactor core to coolant in the RCS and (2) sufficient RCS inventory is necessary to transport heat from the reactor core to the heat sink via natural circulation. Furthermore, inasmuch as heat removal requirements for the ELAP event consider only residual heat, the RCS inventory should be replenished with borated coolant in order to maintain the reactor in a subcritical condition as the RCS is cooled and depressurized.

As reviewed in this section, the licensee's core cooling analysis for the ELAP/LUHS event presumes that, per endorsed guidance from NEI 12-06, both units would have been operating at full power prior to the event. Therefore, the SGs may be credited as the heat sink for core cooling during the ELAP/LUHS event. Maintenance of sufficient RCS inventory, despite ongoing system leakage expected under ELAP conditions, is accomplished through a combination of installed systems and FLEX equipment. The specific means used by the licensee to accomplish adequate core cooling during the ELAP/LUHS event are discussed in further detail below. The licensee's strategy for ensuring compliance with Order EA-12-049 for conditions where one or more units are shut down or being refueled is reviewed separately in Section 3.11 of this evaluation.

3.2.1 Core Cooling Strategy and RCS Makeup

3.2.1.1 Core Cooling Strategy

3.2.1.1.1 Phase 1

As stated in the licensee's FIP, the heat sink for core cooling in Phase 1 would be provided by the two SGs at each unit, which would be fed by the unit's TDAFWP with inventory supplied by the unit's CST, which is seismically qualified. The CST is protected from wind-borne missiles up to a height of six feet above the TDAFWP suction connection, giving it a creditable minimum volume of 14,100 gallons per unit for SG makeup after the worst-case missile strike. The licensee calculates that this represents 1 hour and 53 minutes of decay heat removal time.

Prior to depletion of the CST, operators will align the installed DDFP to take suction from the SW pump bay in the CWPH and discharge to the suction of the TDAFWP via the service water header. The CWPH structure is fully protected from all applicable external hazards discussed in Section 3.5 of this safety evaluation (SE). The licensee has validated that the operators will be able to complete the required actions before the CST credited volume is depleted. The DDFP and its associated piping are seismically qualified. The rate of feedwater flow to the SGs is initially 300 gallons per minute (gpm) (per unit) with the TDAFWP taking suction from the CST. FSG 2 directs operators to reduce flow to 100 gpm during the transition to the DDFP supplying suction to the TDAFWP and then flow is adjusted as necessary for decay heat removal.

The TDAFWP turbine steam supply and exhaust lines are not fully protected against wind-borne missiles. However, the licensee stated that missile protection for the AFW system is based on separation and redundancy, and cross-connect piping has also been installed on the two units' TDAFWP steam supply piping and feedwater discharge lines to improve system redundancy. Therefore, damage to the steam exhaust piping of one TDAFWP will not render the pumps inoperable. Section 3.2.3.1.1 of this SE provides additional details on the TDAFW system.

Following closure of the main steam isolation valves, as would be expected in an ELAP event, steam release from the SGs to the atmosphere would be accomplished via the MSSVs or the SG ADVs. ECA-0.0, "Loss of All AC Power," directs operators to establish manual control of the SG ADVs to control steam release to control RCS temperature. Each SG ADV is potentially vulnerable to a tornado missile strike; however, the licensee states that the ADVs are physically separated and partially protected by the containment structure. Therefore, a single missile will not damage both ADVs. Section 3.2.3.1.1 of this SE provides additional details on the ADVs. Analysis of the potential uncontrolled asymmetric cooldown is discussed in Section 3.2.3.2, Thermal-Hydraulic Analyses. Analysis of the impact of an asymmetric cooldown on boron mixing is discussed in Section 3.2.3.4, Shutdown Margin Analysis.

3.2.1.1.2 Phase 2

The licensee's FIP states that the primary strategy for core cooling in Phase 2 would be to continue using the SGs as a heat sink, with SG secondary inventory supplied by the TDAFWP, which in turn is supplied by the DDFP taking suction from the SW pump bay. As the SW pump bay draws from the UHS (Lake Michigan), this represents an effectively unlimited source of secondary makeup. Since the licensee is using installed, robust equipment to satisfy Phase 2 requirements of the order, it could be considered as an alternative to NEI 12-06. However, the licensee indicated that to satisfy provisions of the order, and to be consistent with NEI 12-06, operators will deploy an onsite portable, diesel driven SG makeup FLEX pump (PDSG) to provide backup for this essential function.

The licensee noted that functionality of the robust TDAFWP is expected well into Phase 2 or until Phase 3 equipment arrives onsite from NSRC. However, in the event that a TDAFWP fails, or steam pressure is no longer sufficient to drive the pump turbine, the PDSG pump would take suction from the SW pump bay or forebay, and discharge to a connection on the motor driven auxiliary feedwater pump (MDAFWP) cross-connect line, which allows the pump to supply both SGs of both units. Alternate suction for the PDSG would be via direct draft from Lake Michigan; the alternate discharge point is at the B.5.b (i.e., 10 CFR 50.54(hh)(2)) connections on the condensate system, which also allows the pump to fully support both units. Two PDSG pumps are stored onsite, which represents "N+1" capability, as a single pump has enough capacity (325 gpm at 400 psig) to provide decay heat removal flow to both units simultaneously.

Assuming both SGs are available, symmetric cooldown of the RCS would begin approximately 12 hours after the initiating event (concurrent with RCS boration). Operators would control the cooldown rate via manual control of the SG ADVs. If one SG is not available (i.e., if an ADV has been damaged) operators would commence an asymmetric cooldown 15 hours after the initiating event, after the completion of RCS boration, which would begin at 8 hours into the event. The licensee states that Calculation CN-NO-08-5, "Point Beach Units 1 and 2 Appendix R and Main Steam Line Break (MSLB) Cooldown Evaluations to RHR Cut-In Conditions for the 1800 MWt Uprating," demonstrates that operators could, if necessary, perform an effective natural circulation cooldown on a single loop, all the way to RHR cut-in conditions (i.e., RCS temperature less than 350 °F). In either case, this initial cooldown would proceed at a rate of no more than 100 °F/hour (in the RCS cold legs) and end when pressure in the intact SG(s) reaches 320 psig. Pausing the cooldown at 320 psig will prevent injection of the nitrogen cover gas in the SI accumulators into the RCS. After the accumulators have been isolated (see Section 3.2.1.2), the intact SG(s) would be further depressurized to 120 psig for long-term cooling.

3.2.1.1.3 Phase 3

The Phase 3 strategy for core cooling is a continuation of the Phase 2 strategy. In addition, according to its FIP, Point Beach's core cooling strategy for Phase 3 would be to establish SDC, which will require additional equipment supplied by the NSRC. The NSRC equipment is scheduled to arrive at the site 24 hours into the event. The NSRC will furnish a pumping system with a capacity of 5000 gpm, which will take suction from Lake Michigan via direct draft, the CWPH SW pump bay or the CWPH forebay. The pump discharge will be directed to the SW system, which allows it to cool the CCW heat exchanger which in turn cools the RHR heat exchanger. The CCW pumps, RHR pumps, and safeguards buses will be re-powered by two 1-MW 4160 Vac DGs.

3.2.1.2 RCS Makeup Strategy

3.2.1.2.1 Phase 1

Following the reactor trip at the start of the ELAP event, operators will isolate RCS letdown pathways and confirm the existence of natural circulation flow in the RCS. A small amount of RCS leakage will occur through the RCP low leakage seals, but because the expected inventory loss would not be sufficient to drain the pressurizer prior to the RCS cooldown, its overall impact on the RCS behavior will be minor. There is no requirement to initiate boration or RCS makeup within the first several hours of the event.

3.2.1.2.2 Phase 2

In Phase 2, RCS inventory control and boration are accomplished with portable equipment stored in the Class I primary auxiliary building (PAB). In the course of cooling and depressurizing the SGs to a target pressure of 320 psig, a significant fraction of the accumulator liquid inventory may inject into the RCS, filling volume vacated by the thermally induced contraction of RCS coolant and system leakage. However, crediting boration from the accumulators is challenging because actual RCS leakage may be quite small, and furthermore, dependent upon the rate of heat loss from the RCS (i.e., particularly from the reactor vessel upper head), RCS pressure may remain several hundred psi above the SG target pressure for multiple hours into the event. Thus, in order to ensure long-term subcriticality as positive reactivity is added from the RCS cooldown and xenon decay, RCS boration will commence using a portable high-pressure FLEX pump no later than 12 hours into the ELAP/LUHS event. With low-leakage Westinghouse Generation 3 SHIELD RCP seals installed on all RCPs, the licensee calculated that FLEX RCS makeup is not necessary to prevent the onset of reflux cooling for at least several days into the event. Therefore, the injection of borated RCS makeup water for reactivity control will be in progress long before entry into reflux cooling becomes a concern.

The primary method of boration and inventory control in Phase 2 is a portable diesel-driven charging pump (PDCP) with a capacity of 15 gpm at 2000 psig. The pump (one for each unit) will be deployed to inject borated water from the unit's RWST to the RCS via the CVCS charging pump discharge drain line valve on either the "A" or "B" loop, which represent primary and alternate connection points. The RWST is seismically qualified, and protected against tornado missiles by adjacent Class I structures up to the 46 ft. plant elevation. The licensee only credits this protected volume, which is approximately 123,000 gallons, which is well in excess of the volume required for boration and RCS inventory control. The boric acid storage tanks (BASTs), which are seismically robust and located within the PAB structure, are considered a backup source of borated water for RCS injection, and contain 7,470 gallons of borated water per unit.

In Phase 2, the SI accumulators will be isolated per the procedure in FLEX support guideline (FSG)-10, Passive RCS Injection Isolation, to prevent injection of the nitrogen cover gas into the RCS. This will be accomplished by powering the accumulator discharge isolation valves from portable 480 VAC FLEX DGs. The sequence of events timeline in the licensee's FIP states that this will be performed at 13 hours into the ELAP event, and that it must be completed prior to SG pressure being lowered to 320 psig.

3.2.1.2.3 Phase 3

The Phase 3 strategy for indefinite RCS inventory control and subcriticality is simply a continuation of the Phase 2 strategy, with backup injection pumps supplied by the NSRC. The installation of low-leakage SHIELD RCP seals minimizes RCS leakage such that the credited volume in the BASTs and RWST will be able to provide RCS makeup source for several days after the event.

3.2.2 Variations to Core Cooling Strategy for Flooding Event

In its FIP, Section 3.5.2, the licensee states that reevaluated flood heights for external flooding are all bounded by the license basis level for protection of critical equipment (+9.0 feet) with the sole exception of local intense precipitation (LIP). The FIP states that LIP flood levels may exceed the +9.0 foot level for the turbine building (TB) and areas outside the TB, but that flood waters would recede below that level "well in advance of the deployment of FLEX equipment" to those areas. Therefore, there are no variations to the core cooling strategy in the event of a flood.

3.2.3 Staff Evaluations

3.2.3.1 Availability of Structures, Systems, and Components (SSCs)

Guidance document NEI 12-06 provides guidance that the baseline assumptions have been established on the presumption that other than the loss of the ac power sources and normal access to the UHS, installed equipment that is designed to be robust with respect to design basis external events is assumed to be fully available. Installed equipment that is not robust is assumed to be unavailable. Below are the baseline assumptions for the availability of SSCs for core cooling during an ELAP caused by a BDBEE.

3.2.3.1.1 Plant SSCs

In the FIP, Section 3.2.1.1 states that the TDAFW pump will provide flow from the CSTs to the SGs to make-up for steam release during Phase 1 Core Cooling. In updated final safety analysis report (UFSAR) Section 10.2.1, it states that the safety-related portions of the auxiliary feedwater (AFW) system are designed as seismic Class I, and are capable of withstanding design basis earthquake accelerations without a loss of system performance capability. Point Beach UFSAR Section 10.2.5 states the major portions of the AFW system reside within seismic Class I structures. The UFSAR explains that portions of the steam supply lines to the TDAFW pumps run through the facades (which can be reasonably expected to envelope the safe shutdown earthquake (SSE) loads) and portions of the PAB steel frame superstructure (which was analyzed to be capable of withstanding an SSE). Furthermore, portions of the AFW system are located in the TB, which was also analyzed to withstand SSE loads. In the FIP, Section 3.2.2.1.1 states that the TDAFW pump and its associated components are located above the 9-ft. elevation; therefore, they are protected from external flooding (See UFSAR Section 2.5). Based on the design and location of the TDAFW pump and associated components, these components should be available to support core cooling during an ELAP caused by a BDBEE.

The licensee explained that since the TDAFW pump turbine exhaust line is not fully protected against tornado missiles, the exhaust piping has been modified, with a normally-open (unless isolated for maintenance) cross-connect valve, to cross connect the steam exhaust of each unit's TDAFW pump turbines with a passive design. This modification is to ensure that a single missile does not render the TDAFW pumps inoperable. The licensee also explained that the cross connect piping between each unit's TDAFW pump steam supply lines and cross connect piping between each unit's TDAFW pump discharge lines were installed to improve system redundancy and the capability to handle multiple failures. These cross-connect paths are normally closed; procedure FSG-15, "Turbine Drive AFW Pump Cross Tie," directs operators to align these cross-connections if necessary. The licensee has validated the time required to complete this action. The staff noted that UFSAR Section 1.3.1 describes separation between redundant systems or components as providing reasonable assurance that a single missile cannot render both systems or components inoperable. During the audit process, the staff reviewed the licensee's calculations and engineering change (EC) documentation, and verified that a single TDAFWP steam supply line, exhaust line, and feedwater discharge line could effectively support both units during an ELAP/LUHS event. Based on the licensee's current licensing basis, the TDAFW exhaust line, steam supply line and pump discharge line cross-connects should be available during an ELAP following a high wind event.

In the FIP, Section 3.2.1.1 indicates that once the CST is no longer a viable suction source for the TDAFW pump, the DDFP will take suction from the SW pump bay in CWPH and discharge into the suction of the TDAFW pump to continue supporting Phase 1 core cooling. The staff noted that the seismically designed DDFP and associated piping (see FIP Section 3.2.2.1.1) is located in the CWPH. In UFSAR Section A.5.2 it indicates that the CWPH is a seismic Class I structure and UFSAR Section 1.3.1 states that the seismic Class I portions of the CWPH is designed to withstand the effects of a tornado (i.e., wind force, pressure differential, and missile impingement). In UFSAR Section 2.5 the licensee indicates that all important equipment in the CWPH, including diesel fire pump engine and the control panel and battery for the diesel fire pump, is located above the maximum possible flood height within the building and would not be subject to flooding. Based on the location and design of the DDFP (including associated piping and electrical components), it should be available to support core cooling during an ELAP caused by a BDBEE.

In the FIP, Section 3.2.1.1 states that the licensee's existing plant procedure directs manual control of the SG ADVs for steam release. The staff noted during its audit that the ADVs are located within the façade and significantly above grade elevation. Furthermore, UFSAR Section 10.1.2 indicates that the MSSVs and ADVs are seismic Class 1 components. The licensee explained that the SG ADVs are physically separated and partially protected by the containment structure; thus, a single missile will not adversely impact the operation of both ADVs simultaneously. In UFSAR Section 1.3.1 the licensee indicates that tornado missile protection of systems and components can be accomplished by separation between redundant systems or components; and large structure are designed that they will not collapse on redundant components or systems. Furthermore, the licensee performed evaluation SL-012991, "Tornado Missile Strike Probability for Atmospheric Dump Valves, Main Steam Relief Valves, and AFW Steam Supply Lines to Steam Driven Turbine," Revision 0, that concluded the probability of a missile causing significant damage striking both main steam line components is low and is not considered credible. Additionally, the evaluation determined that it is reasonable that at least one set of ADVs, MSSVs and the Steam Supply line for the AFW pump will be available during an ELAP event following a high wind event. These conclusions were based on strike probability, height above grade, typical missiles, typical tornado paths and shielding by intervening structures. Based on the design and location of the components, the current licensing basis for tornado missile protection, and the licensee's evaluation regarding the likelihood of a missile strike damaging both sets of main steam line components, these components should be available during an ELAP event.

3.2.3.1.2 Plant Instrumentation

According to the FIP, the following instrumentation would be relied upon to support the licensee's core cooling and RCS inventory control strategy:

- TDAFW flow
- SG water level
- SG pressure
- RCS hot leg temperature
- RCS cold leg temperature
- core exit thermocouples
- CST level
- pressurizer level
- reactor vessel level
- neutron flux
- RCS pressure (wide range)
- DC bus voltage
- SI accumulator pressure
- Containment pressure
- Containment temperature

The licensee's FIP states that at least one channel of the above essential instrumentation will be available prior to and after load stripping of the dc and ac buses during Phase 1. The operators would perform dc bus load shedding to extend battery life to 10 hours, and a FLEX DG would repower battery chargers prior to battery depletion, ensuring the availability of the essential instrumentation during Phases 2 and 3.

Procedure FSG-7, "Loss of Vital Instrumentation or Control Power," provides location and terminal information for all essential instrumentation. Portable FLEX equipment (battery/inverter carts, multi-meters, digital thermometers, etc.) is supplied with installed local instrumentation as needed to operate the equipment.

3.2.3.2 Thermal-Hydraulic Analyses

RCS Inventory

NextEra concluded that its mitigating strategy for reactor core cooling would be adequate based, in part, on a plant-specific thermal-hydraulic analysis performed using the NOTRUMP computer code. The NOTRUMP code and corresponding evaluation model were originally submitted in the early 1980s as a method for performing licensing-basis safety analyses of small-break loss-of-coolant accidents (LOCAs) for Westinghouse PWRs. Although NOTRUMP has been approved for performing small-break LOCA analysis under the conservative Appendix K paradigm and constitutes the current evaluation model of record for many operating PWRs, the NRC staff had not previously examined its technical adequacy for performing best-estimate simulations of the ELAP event. Therefore, in support of mitigating strategy reviews to assess compliance with Order EA-12-049, the NRC staff evaluated licensees' thermal-hydraulic analyses, including a limited review of the significant assumptions and modeling capabilities of NOTRUMP and other thermal-hydraulic codes used for these analyses. The NRC staff's review included performing confirmatory analyses with the TRACE code to obtain an independent assessment of the duration that reference reactor designs could cope with an ELAP event prior to providing makeup to the RCS.

Based on its review, the NRC staff questioned whether NOTRUMP and other codes used to analyze ELAP scenarios for PWRs would provide reliable coping time predictions in the reflux or boiler-condenser cooling phase of the event because of challenges associated with modeling complex phenomena that could occur in this phase, including boric acid dilution in the intermediate leg loop seals, two-phase leakage through RCP seals, and primary-to-secondary heat transfer with two-phase flow in the RCS. Due to the challenge of resolving these issues within the compliance schedule specified in Order EA-12-049, the NRC staff requested that industry provide makeup to the RCS prior to entering the reflux or boiler-condenser cooling phase of an ELAP, such that reliance on thermal-hydraulic code predictions during this phase of the event would not be necessary.

Accordingly, the ELAP coping time prior to providing makeup to the RCS is limited to the duration over which the flow in the RCS remains in natural circulation, prior to the point where continued inventory loss results in a transition to the reflux or boiler-condenser cooling mode. In particular, for PWRs with inverted U-tube SGs, the reflux cooling mode is said to exist when vapor boiled off from the reactor core flows out the saturated, stratified hot leg and condenses on SG tubes, with the majority of the condensate subsequently draining back into the reactor vessel in countercurrent fashion. Quantitatively, as reflected in documents such as the PWR Owners Group (PWROG) report PWROG-14064-P, Revision 0, "Application of NOTRUMP Code Results for Westinghouse Designed PWRs in Extended Loss of AC Power Circumstances," industry has proposed defining this coping time as the point at which the one-hour centered time-average of the flow quality passing over the SG tubes' U-bend exceeds one-tenth (0.1). As discussed further in Section 3.2.3.4 of this SE, a second metric for ensuring adequate coping time is associated with maintaining sufficient natural circulation flow in the RCS to support adequate mixing of boric acid.

With specific regard to NOTRUMP, preliminary results from the NRC staff's independent confirmatory analysis performed with the TRACE code indicated that the coping time for Westinghouse PWRs under ELAP conditions could be shorter than predicted in WCAP-17601-P, "Reactor Coolant System Response to the Extended Loss of AC Power Event for Westinghouse, Combustion Engineering and Babcock & Wilcox NSSS Designs." Subsequently, a series of additional simulations performed by the staff and Westinghouse identified that the discrepancy in predicted coping time could be attributed largely to differences in the modeling of RCP seal leakage. (The topic of RCP seal leakage will be discussed in greater detail in Section 3.2.3.3 of this SE.) These comparative simulations showed that when similar RCP seal leakage boundary conditions were applied, the coping time predictions of TRACE and NOTRUMP were in adequate agreement. From these simulations, as supplemented by review of key code models, the NRC staff obtained sufficient confidence that the NOTRUMP code may be used in conjunction with the WCAP-17601-P evaluation model for performing best-estimate simulations of ELAP coping time prior to reaching the reflux cooling mode.

NextEra requested that Westinghouse perform two plant-specific NOTRUMP calculations to address RCS thermal-hydraulic analysis and boron mixing. Those analyses are documented in Calculation CN-SEE-II-14-15, "Point Beach Nuclear Plant RCS Makeup Boration Evaluation for a Beyond Design Basis Extended Loss of All AC Power Event," and Calculation CN-LIS-14-30, "Point Beach Extended Loss of Alternating Current Power (ELAP) Calculations for Boron Mixing Strategy." During the audit process, the staff reviewed these calculations and concluded that, particularly due to the installations of low-leakage SHIELD seals, the licensee could maintain natural circulation flow in the RCS for multiple days during the ELAP event prior to requiring RCS makeup, whereas RCS makeup would be available per the licensee's mitigating strategy within 12 hours. (The staff's conclusions regarding boron mixing are discussed in Section 3.2.3.4 of this SE.)

Therefore, based on the evaluation above, the licensee's analytical approach should appropriately determine the sequence of events, including time-sensitive operator actions, and evaluate the required equipment to mitigate the analyzed ELAP event, including pump sizing and cooling water capacity.

3.2.3.3 Reactor Coolant Pump (RCP) Seals

Leakage from RCP seals is among the most significant factors in determining the duration that a PWR can cope with an ELAP event prior to initiating RCS makeup. An ELAP event would interrupt cooling to the RCP seals, resulting in the potential for increased seal leakage and the failure of elastomeric o-rings and other components, which could further increase the leakage rate. As discussed above, as long as adequate inventory is maintained in the RCS, natural circulation can effectively transfer residual heat from the reactor core to the SGs and limit local variations in boric acid concentration. Along with cooldown-induced contraction of the RCS inventory, cumulative leakage from RCP seals governs the duration over which natural circulation can be maintained in the RCS. Furthermore, the seal leakage rate at the depressurized condition can be a controlling factor in determining the flow capacity requirement for FLEX pumps to offset ongoing RCS leakage and recover adequate system inventory.

Generation 3 SHIELD low-leakage RCP seals have been installed on all of the RCPs at Point Beach. The SHIELD seal incorporates a thermally driven actuator mechanism that is designed to initiate automatically upon a loss of seal cooling. Upon activation, the seals are designed to allow a leakage rate of less than 1 gpm per RCP.

The NRC staff's audit review considered whether the SHIELD low-leakage seals have been credited in Point Beach's FLEX strategy in accordance with the four conditions identified in the NRC's endorsement letter of Westinghouse's white paper TR-FSE-14-1-P, "Use of Westinghouse SHIELD Passive Shutdown Seal for FLEX Strategies," dated May 28, 2014 (ADAMS Accession No. ML14132A128). The staff's audit review concluded that the licensee conforms to each condition from the NRC staff's endorsement letter as follows:

> Condition 1: Credit for the SHIELD seals is only endorsed for Westinghouse RCP Models 93, 93A, and 93A-1.

This condition is satisfied because the RCPs at Point Beach are Westinghouse Model 93 RCPs.

> Condition 2: The maximum steady-state reactor coolant system (RCS) cold-leg temperature is limited to 571°F during the ELAP (i.e., the applicable main steam safety valve setpoints result in an RCS cold-leg temperature of 571°F or less after a brief post-trip transient).

The maximum steady-state RCP seal temperature during an ELAP event is expected to be the RCS cold leg temperature corresponding to the lowest SG safety relief valve setting. Per the Point Beach technical specifications, the nominal lift setpoint is 1085 psig, with a ±3 percent tolerance. Therefore, this condition is satisfied, since the saturation temperature at this pressure (with ±3 percent tolerance applied) implies an RCS cold leg temperature of approximately 560 °F.

> Condition 3: The maximum RCS pressure during the ELAP (notwithstanding the brief pressure transient directly following the reactor trip comparable to that predicted in the applicable analysis case from WCAP-17601-P) is as follows: For Westinghouse Models 93 and 93A-1 RCPs, RCS pressure is limited to 2250 psia; for Westinghouse Model 93A RCPs, RCS pressure is to remain bounded by Figure 7.1-2 of TR-FSE-14-1-P, Revision 1.

Normal operating pressure at Point Beach is 2235 psig, per the plant's UFSAR. Allowing for the possibility of a brief pressure transient directly following the reactor trip, the NRC staff concludes that the licensee's mitigating strategy of cooling the reactor core via the main steam safety valves and SG ADVs should otherwise maintain reactor pressure below 2250 psia.

> Condition 4: Nuclear power plants that credit the SHIELD seal in an ELAP analysis shall assume the normal seal leakage rate before SHIELD seal actuation, and a constant seal leakage rate of 1.0 gallon per minute for the leakage after SHIELD seal actuation.

The licensee's FIP and supporting calculations assume a constant Westinghouse SHIELD RCP seal package leakage rate of 1 gpm per RCP, plus 1 gpm of unidentified RCS leakage, for a total RCS leakage of 3 gpm. The actual seal leakage rate expected during an ELAP event would exceed this value for a brief period prior to actuation of the SHIELD seal (according to the actuation range specified in TR-FSE-14-1-P, actuation of the SHIELD seal would occur well within one hour of ELAP event initiation). As noted previously, the licensee has calculated that reflux cooling would not be entered for multiple days into the event, even if FLEX RCS makeup flow were not provided as planned. In that Point Beach's mitigating strategy directs RCS makeup to begin approximately 12 hours after event initiation (or 8 hours, in the event that an asymmetric cooldown is necessary), ample margin exists to accommodate the small additional volume of leakage that is expected to occur prior to actuation of the SHIELD seal.

The seal leakoff analysis assumes no failure of the seal design, including the elastomeric o-rings. During the audit review, the licensee confirmed that the installed RCP SHIELD seal o-rings and the o-rings upstream of the SHIELD seal package are qualified for the maximum expected RCS cold leg temperature (559.9°F). Based on these factors, the staff's audit review concluded that o-ring failure for Point Beach during a beyond-design-basis ELAP event would not be expected.

Based upon the discussion above, the NRC staff concludes that the RCP seal leakage rates assumed in the licensee's thermal-hydraulic analysis may be applied to the beyond-design basis ELAP event for the site.

3.2.3.4 Shutdown Margin Analyses

In the analyzed ELAP event, the loss of electrical power to control rod drive mechanisms is assumed to result in an immediate reactor trip with the full insertion of all control rods into the core. The insertion of the control rods provides sufficient negative reactivity to achieve subcriticality at post-trip conditions. However, as the ELAP event progresses, the shutdown margin for PWRs is typically affected by several primary factors:

- the cooldown of the RCS and fuel rods adds positive reactivity
- the concentration of xenon-135, which (according to the core operating history assumed in NEI 12-06) would
  - initially increase above its equilibrium value following reactor trip, thereby adding negative reactivity
  - peak at roughly 12 hours post-trip and subsequently decay away gradually, thereby adding positive reactivity
- the passive injection of borated makeup from nitrogen-pressurized accumulators due to the depressurization of the RCS, which adds negative reactivity

At some point following the cooldown of the RCS, PWR licensees' mitigating strategies generally require active injection of borated coolant via FLEX equipment. In many cases, boration would become necessary to offset the gradual positive reactivity addition associated with the decay of xenon-135; but, in any event, borated makeup would eventually be required to offset ongoing RCS leakage. The necessary timing and volume of borated makeup depend on the particular magnitudes of the above factors for individual reactors.

The specific values for these and other factors that could influence the core reactivity balance that are assumed in the licensee's current calculations could be affected by future changes to the core design. However, NEI 12-06, Section 11.8 states that "[e]xisting plant configuration control procedures will be modified to ensure that changes to the plant design . . . will not adversely impact the approved FLEX strategies." Inasmuch as changes to the core design are changes to the plant design, the NRC staff expects that any core design changes, such as those considered in a core reload analysis, will be evaluated to determine that they do not adversely impact the approved FLEX strategies, especially the analyses which demonstrate that recriticality will not occur during a FLEX RCS cooldown.

During the audit, the NRC staff reviewed the licensee's shutdown margin calculation. The licensee has a portable Phase 2 boration strategy employing one PDCP at each unit; each

PDCP has a capacity of 15 gpm at 2000 psig. Primary and alternate injection pathways to the RCS cold legs are available (i.e., FLEX connections to the discharge drain valves downstream of two different charging pumps at each unit). The licensee determined that this strategy can provide approximately 6000 gallons of 2800 ppm boric acid solution to the RCS from the RWST (or approximately 3000 gallons of highly concentrated BAST water); this is sufficient to maintain at least 1 percent shutdown margin in the RCS, even as the RCS cools down and xenon decays.

Toward the end of an operating cycle, when RCS boron concentration reaches its minimum value, some PWR licensees may need to vent the RCS to ensure that their FLEX strategies can inject a volume of borated coolant that is sufficient to satisfy shutdown margin requirements. The licensee's analysis concluded that, because the RCS volume shrinks as it cools down, the required volume of boric acid solution could be injected without having to vent the RCS if a symmetric two-loop cooldown is being performed concurrent with boration, which is the primary strategy according to the FIP. In the event that one ADV is damaged, operators would perform an asymmetric cooldown after boration is completed. In any case, Procedure FSG-8, "Alternate RCS Boration," directs operators to verify that RCS conditions (i.e. RCS pressure and pressurizer level) will support boration, and if necessary, vent the RCS via the dc-powered reactor vessel head vent valves to accommodate the injection volume required to ensure 1% SDM. Pressurizer vents would only be used if the head vent valves were unavailable.

The NRC staff's audit review of the licensee's shutdown margin calculation determined that credit was taken for uniform mixing of boric acid during the ELAP event. The NRC staff had previously requested that the industry provide additional information to justify that borated makeup would adequately mix with the RCS volume under natural circulation conditions potentially involving two-phase flow. In response, the PWROG submitted a position paper, dated August 15, 2013 (withheld from public disclosure due to proprietary content), which provided test data regarding boric acid mixing under single-phase natural circulation conditions and outlined applicability limits intended to ensure that boric acid addition and mixing during an ELAP would occur under conditions similar to those for which boric acid mixing data is available. By letter dated January 8, 2014 (ADAMS Accession No. ML13276A183), the NRC staff endorsed the above position paper with three conditions:

> Condition 1: The required timing and quantity of borated makeup should consider conditions with no RCS leakage and with the highest applicable leakage rate.

This condition is satisfied because the licensee's planned timing for establishing borated makeup acceptably considered both the maximum and minimum RCS leakage conditions expected for the analyzed ELAP event.

> Condition 2: Adequate borated makeup should be provided either (1) prior to the RCS natural circulation flow decreasing below the flow rate corresponding to single-phase natural circulation, or (2) if provided later, then the negative reactivity from the injected boric acid should not be credited until one hour after the flow rate in the RCS has been restored and maintained above the flow rate corresponding to single-phase natural circulation.

This condition is satisfied because the licensee's planned timing for establishing borated makeup would be prior to RCS flow decreasing below the expected flow rate corresponding to single-phase natural circulation for the analyzed ELAP event.

> Condition 3: A delay period adequate to allow the injected boric acid solution to mix with the RCS inventory should be accounted for when determining the required timing for borated makeup. Provided that the flow in all loops is greater than or equal to the corresponding single-phase natural circulation flow rate, a mixing delay period of 1 hour is considered appropriate.

This condition is satisfied because the licensee's planned timing for establishing borated makeup allows a 1-hour period to account for boric acid mixing; furthermore, during this 1-hour period, the RCS flow rate would exceed the single-phase natural circulation flow rate expected during the analyzed ELAP event.

During the audit review, NextEra confirmed that Point Beach will comply with the August 15, 2013, position paper on boric acid mixing, including the above conditions imposed in the staff's corresponding endorsement letter. The NRC staffs audit review indicated that the licensee's shutdown margin calculations are generally consistent with the PWROG's position paper, including the three additional conditions imposed in the NRG staff's endorsement letter.

Therefore, based on the evaluation above, the NRC staff concludes that the sequence of events in the proposed mitigating strategy should result in acceptable shutdown margin for the analyzed ELAP event.

3.2.3.5 FLEX Pumps and Water Supplies

In the FIP, Section 3.2.2.5.1 indicates that SG feedwater injection is provided by a portable FLEX PDSG pump, which is rated for 325 gpm at 400 psig, through a primary or alternate connection. The FLEX PDSG pump is a trailer-mounted, diesel driven engine, centrifugal pump stored in the FLEX Storage Building (FSB) and is intended to be a back-up SG injection method in the event that the TDAFW pump can no longer perform its function. One FLEX PDSG pump has sufficient capacity to provide decay heat removal flow to both units; thus, two FLEX PDSG pumps are available to satisfy the N+1 requirement.

The licensee indicated that its hydraulic analysis, Calculation 2015-04238, "Hydraulic Analysis of Flow Path with the Supply of Lake Water to the SGs via the AFW System During a FLEX Scenario," Revision 1, assessed whether the FLEX PDSG pump rated at 325 gpm at 400 psig can provide sufficient makeup to the SGs (both units) and to the SFP. The licensee's evaluation considered line losses from temporary hoses (e.g., bends and friction), line losses through installed piping, elevation losses, and determined the required net positive suction head (NPSH) for the FLEX PDSG pump. The staff noted that the licensee determined that the total developed head at the required flow rates to the SGs and SFP (~920 ft.) is bounded by the capability of the FLEX PDSG pump (~990 ft. with a flowrate of 315 gpm operating at 3600rpm). In addition, the licensee determined that the available NPSH with Lake Michigan as the suction source is greater than the required NSPH. During its audit, the staff noted that FSG-5.4, "FLEX Pump Operations," provides guidance to operators such as available suction sources to the FLEX PDSG pump, and routing and connecting suction and discharge hoses for the pump. In addition, diagrams of the connection points and hose routes are provided in the FSG to assist the operators during an ELAP event.

In the FIP, Section 3.2.2.5.2 indicates that RCS injection is provided by a PDCP, which is rated for 15 gpm at 2000 psig, through a primary and alternate connection. The FLEX PDCP is a diesel driven low capacity, high pressure pump stored on the 8 ft. elevation of the PAB. A separate PDCP is provided for each unit; thus, three PDCP pumps are available to satisfy the N+1 requirement.

The licensee indicated that its hydraulic analysis, Calculation 2013-12974, "Evaluation of Portable Diesel Drive Charging Pump for High pressure RCS Makeup," August, 27, 2015, assessed whether a charging pump rated for 15 gpm at 2000 psig is capable of providing sufficient makeup to the RCS via the CVCS system through the portable connection points. The licensee's evaluation considered line losses from temporary hoses (including bends, couplings and manifolds), line losses through installed piping, fittings and valves and determined the minimum RWST level to ensure adequate NPSH to the FLEX PDCP. The staff noted the licensee determined the maximum allowable RCS pressure to ensure that the FLEX PDCP can accomplish injecting 15 gpm to the RCS via the primary and alternate connection points. During its audit, the staff noted that FSG-5.4, "FLEX Pump Operations," provides guidance to operators such as routing and connecting suction and discharge hoses for the FLEX PDCP, identifying the necessary valve manipulations to align flowpaths and routing of exhaust hose for the FLEX PDCP. In addition, diagrams of the connection points (discharge and suction) and hose routing are provided in the FSG to assist the operators during an ELAP event.

Based on the staff's review of the FLEX pumping capabilities at Point Beach, as described in the above hydraulic analyses and the FIP, the licensee's portable FLEX pumps should have sufficient capacity to support core cooling during an ELAP consistent with the provisions of NEI-12-06, Section 11.2.

3.2.3.6 Potential Uncontrolled Asymetric Cooldown

As noted in Section 3.2.3.1.1, SG ADVs and TDAFWP steam supply lines are not fully protected against wind-borne missile hazards. The licensee evaluated the impact of an uncontrolled RCS cooldown due to an un-isolable steam line break resulting from a tornado missile strike on an ADV, MSSV, or TDAFWP steam supply line. In Calculation 2015-07502, "Evaluation of Atmospheric Dump Valves, Main Steam Relief Valves and AFW Steam Supply Line Tornado Missile Effects," Revision 0, the bounding case was found to be shearing or breaking of the 6-inch diameter branch connection to an ADV (all other branch connections are smaller or the same diameter). The licensee determined that the probability of blowdown of both SGs resulting from damage to multiple components was so low as to not be credible.

Westinghouse analysis CN-TA-15-31, "Point Beach Uncontrolled Asymmetric Cooldown during ELAP Analysis," Revision 0, provides the plant response to an uncontrolled RCS cooldown due to missile damage to a single SG and subsequent cooldown during an ELAP event. The analysis determined the effects on RCS temperature, RCS pressure, shutdown margin, and other key parameters using the RETRAN code. The analysis considered two steam leak sizes, a stuck open MSSV and a sheared-off MSSV/ADV, and evaluated two different operator response times for isolating feed flow to the faulted SG, 10 minutes and 20 minutes. Since the analysis was performed, ECA-0.0 was revised to include a step in the foldout page to address a faulted SG, which allows the reactor operator to take action as soon as a faulted condition is recognized. The licensee states that based on time validation performed, operators would check AFW flow at 2 to 3 minutes into the event and would recognize the faulted condition. Thus, the licensee considers a time of 10 minutes for isolating feed flow to the faulted SG (which can be done remotely from the control room) to be a reasonable assumption for the analysis. According to the licensee, results from the analysis show that:

- RCS temperature drops to around 300 °F (worst case) and then recovers.
- For all cases except the worst case (MSSV/ADV shear, with 20 minute time to AFW isolation), RCS cold leg temperature remains above the SHIELD shutdown seal (SDS, see Section 3.2.3.3 of this SE) actuation design temperature range of 260-320 °F, and in all cases remains above the nominal actuation temperature of approximately 282 °F. Therefore, the expected actuation of the SDS (which limits RCS leakage through the seal) would not be threatened by the uncontrolled cooldown. For the worst case, if SDS actuation does not occur prior to reaching minimum cold leg temperature, it would occur after temperature subsequently recovers in both loops.
- There is no return to power in any analyzed case; only the worst case showed a brief (24 second) loss of shutdown margin.
- Voiding in the upper head may occur, but core uncovery does not occur.
- Accumulators may inject but do not empty, and no nitrogen is injected to the RCS.
- RCS pressure recovery does not result in a pressurizer safety valve lift if AFW flow is isolated within 10 minutes.
- The pressurizer and RCS do not go solid for any of the cases.
- Natural circulation in the non-faulted loop is reestablished.

Based on the analysis performed, the licensee states that Point Beach FLEX strategies can be effectively implemented during a BDB/ELAP event with coincident tornado missile damage resulting in an uncontrolled cooldown. Procedure changes were made to allow operators to expeditiously take action to reduce the impact of the uncontrolled cooldown event.

3.2.3.7 Electrical Analyses

The licensee's electrical strategies provide power to the equipment and instrumentation used to mitigate an ELAP event. The electrical strategies described in the FIP are practically identical for restoring core cooling, containment, and SFP cooling, except as noted in Sections 3.3.4.4 and 3.4.4.4 of this SE. Furthermore, the electrical coping strategies are the same for all modes of operation.

The NRC staff reviewed the licensee's FIP, conceptual electrical single-line diagrams, summaries of calculations for sizing the FLEX diesel and turbine generators and station batteries, and summaries of calculations that addressed the effects of temperature on the electrical equipment credited in the FIP as a result of the loss of heating, ventilation, and air conditioning (HVAC) caused by the event. The staff also reviewed the separation and isolation of the FLEX generators from the Class 1E EDGs, and procedures that direct operators how to align, connect, and protect associated systems and components.

The Point Beach Phase 1 FLEX mitigating strategy involves relying on installed plant equipment and onsite resources, such as the installed Class 1E station batteries, vital inverters, and the Class 1E dc electrical distribution system. This equipment is considered robust and protected with respect to applicable site external hazards since they are located within safety-related, Class 1 structures. The dc power from the Class 1E station batteries will be needed in an ELAP to power loads such as shutdown system instrumentation, control systems, and re-powered SOVs and MOVs. Procedure FSG-4, "ELAP DC Bus Load Shed/ Management," Revision 0, directs operators to conserve dc power during the event by shedding nonessential loads. The plant operators would commence stripping, or load shedding, of non-essential dc loads within 1 hour after the occurrence of an ELAP/LUHS event. The licensee expects load shedding to be completed within 1 hour. According to the Point Beach UFSAR, emergency power supply for vital instruments, control power and for some dc emergency lighting of both units is supplied from four 125 Vdc station batteries which are common to both units.

The NRC staff noted that Point Beach had followed the guidance in NEI White Paper, "EA-12-049 Mitigating Strategies Resolution of Extended Battery Duty Cycles Generic Concern" (ADAMS Accession No. ML13241A186), when calculating the duty cycle of the batteries. This paper was endorsed by the NRC (ADAMS Accession No. ML13241A188). In addition to the White Paper, the NRC sponsored testing at Brookhaven National Laboratory that resulted in the issuance of NUREG/CR-7188, "Testing to Evaluate Extended battery Operation in Nuclear Power Plants," in May of 2015. The purpose of this testing was to examine whether existing vented lead acid batteries can function beyond their defined design basis (or beyond-design basis if existing SBO coping analyses were utilized) duty cycles in order to support core cooling. The study evaluated battery performance availability and capability to supply the necessary dc loads to support core cooling and instrumentation requirements for extended periods of time. The testing provided an indication of the amount of time available (depending on the actual load profile) for batteries to continue to supply dc power to the core-cooling equipment beyond the original duty cycles for a representative plant. The testing also demonstrated that battery availability can be significantly extended using load shedding techniques to allow more time to recover ac power. The testing further demonstrated that battery performance is consistent with battery manufacturing performance data. According to the NUREG, the projected availability of a battery can be accurately calculated using the Institute of Electrical and Electronics Engineers (IEEE) Standard 485-2010, "IEEE Recommended Practice for Sizing Lead-Acid batteries for Stationary Applications," or using an empirical algorithm described in the report. The testing provided additional validation that the NEI White Paper method was technically acceptable. The NRC staff reviewed the licensee's battery calculations and confirmed that they had followed the guidance in the NEI White Paper.

The Point Beach Class 1E Station Batteries D-05 and D-06 contain 60 cells each and were manufactured by Exide, (Model GN-23) with a capacity of 1800 Ampere-Hours (A-H)). The Point Beach PAB Class 1E station batteries D-105 and D-106 contain 60 cells each and were manufactured by C&D Technologies (Model LCR-21) with a capacity of 1500 A-H. Station Battery D305 is a reserve safety-related battery manufactured by Exide (Model GN-23), containing 60 cells and a capacity of 1800 A-H that is used for maintenance.

During the onsite audit, the NRC staff reviewed the summary of the licensee's dc system analysis in Calculation 2014-0013, "125 Vdc System Calculation for FLEX Strategy," Revision 0, to verify the capability of the dc system to supply the required loads during the first phase of the

Point Beach, Units 1 and 2 FLEX mitigation strategies plan. In the FIP and calculation 2014-0013, the licensee stated that the total coping time is calculated to be 10 hours with the Class 1E station batteries (D-05 and D-06) connected and 12 hours and 45 minutes for Class 1E station batteries D-105, D-106, and D305 connected. As one of the connected batteries depletes to the minimum acceptable voltage, an operator will switch in the other battery with full capacity to replace the depleted battery. Procedure FSG-4 provides guidance on realigning/switching the batteries when one battery depletes to the minimum acceptable voltage. The licensee's evaluation identified the required loads and their associated ratings (ampere and minimum required voltage) and the loads that would be shed within 2 hours into the ELAP to ensure battery operation for at least 10 hours. The licensee noted, and the staff confirmed, that the useable station battery capacity could be extended for at least 10 hours by load shedding non-essential loads.

Based on the evaluation above, the NRC staff concludes that the Point Beach load shed strategy should ensure that the Class 1E station batteries will have sufficient capacity to supply power to required loads for at least 10 hours for both units provided the load shed is completed within the time assumed in the licensee's analysis.

The licensee's Phase 2 strategy includes re-powering vital battery chargers and 120 Vac instrument buses via the installed inverters within 8 hours using a 404-kilowatt (kW), 480 Vac FLEX DG stored in a robust FSB located onsite. One 480 Vac FLEX DG is required to power the D-107, D108, or D-109 battery charger (76 kW), D-07 or D-08, or D-09 battery charger (58 kW) and SI accumulator isolation valves (5.2 kW). The two FLEX DGs meet the N + 1 requirement. In its FIP, the licensee stated that the transition to Phase 2 equipment would occur earlier (in approximately 8 hours) than the calculated depletion of the Class 1E 125 Vdc batteries (10 hours). The portable 480 Vac FLEX DG would supply power to both units' vital battery chargers and 120 Vac circuits providing continuity of key parameter monitoring and other required loads. The licensee's FLEX DG sizing calculation ECP 279879, "Point Beach Nuclear Plant – Unit 1 and 2 Fukushima FLEX Strategy Implementation Umbrella Modification," Revision 0, identified the total estimated required loads to be approximately 139 kW for the 480 Vac FLEX DG. Procedure FSG-4 provides guidance to the operators for restoration of the battery chargers. The 480 Vac FLEX DG would power safeguard buses 1B03 and 2B03 and motor control centers B-39 and B-49. Therefore, the NRC staff concludes that one 404 kW FLEX DG for both units is adequate to support the electrical loads required for the Phase 2 strategies, and that the licensee's Phase 2 electrical strategy ensures that the safety-related battery chargers will be energized prior to the batteries becoming fully discharged.

For Phase 3, Point Beach plans to continue the Phase 2 coping strategy with additional assistance provided from offsite equipment/resources. The offsite resources that will be provided by the NSRCs include two 1 MW 4160 Vac combustion turbine generators (CTG), a distribution panel (including cables and connectors), and a 480 Vac, 1100 kW CTG per unit.

Each 4160 Vac CTG is capable of supplying approximately 1 MW but two CTGs will be operated in parallel to provide approximately 2 MW (2.5 MVA at .8 pf). The major equipment powered by the 4160 Vac CTGs include a CCW Pump, RHR Pump, AFW Pump, SW Pump, SSG pump, SFP pump, vital battery chargers, and other Phase 2 required loads. In calculation 2004-0002, "AC Electrical System Analysis," Revision 5, the licensee estimated an approximate total Phase 3 loading of 1500 kW. Considering that there are two 4160 Vac CTGs per unit with

1 MW capacity, the two 4160 Vac CTGs in parallel will have adequate capacity to support Phase 3 loads for plant cooldown and SFP cooling. In addition, the 480 Vac CTGs can be used as backup to continue to supply the Phase 2 equipment loads. Based on its review, the NRC staff concludes that the 4160 Vac and 480 Vac equipment being supplied from the NSRCs should have sufficient capacity and capability to supply the required loads to maintain or restore core cooling, SFP cooling, and containment indefinitely following an ELAP.

3.2.4 Conclusions

Based on this evaluation, the NRC staff concludes that the licensee has developed guidance that, if implemented appropriately, should maintain or restore core cooling following a BDBEE consistent with NEI 12-06, as endorsed by JLD-ISG-2012-01, and should adequately address the requirements of the order.

3.3 Spent Fuel Pool Cooling Strategies

Guidance document NEI 12-06, Table 3-2 and Appendix D, summarize an acceptable approach consisting of three separate capabilities for the SFP cooling strategies. This approach uses a portable injection source to provide the capability for 1) makeup via hoses on the refueling floor capable of exceeding the boil-off rate for the design-basis heat load; 2) makeup via connection to SFP cooling piping or other alternate location capable of exceeding the boil-off rate for the design-basis heat load; and 3) spray via portable monitor nozzles from the refueling floor using a portable pump capable of providing a minimum of 200 gpm per unit (250 gpm if overspray occurs). During the event, the licensee selects the method to use based on plant conditions. This approach also requires a strategy to mitigate the effects of steam from the SFP, such as venting.

As described in NEI 12-06, Section 3.2.1.7 and JLD-ISG-2012-01, Section 2.1, strategies that have a time constraint to be successful should be identified and a basis provided that the time can be reasonably met. In NEI 12-06, Section 3 provides the performance attributes, general criteria, and baseline assumptions to be used in developing the technical basis for the time constraints. Since the event is beyond-design-basis, the analysis used to provide the technical basis for time constraints for the mitigation strategies may use nominal initial values (without uncertainties) for plant parameters, and best-estimate physics data. All equipment used for consequence mitigation may be assumed to operate at nominal setpoints and capacities. In NEI 12-06, Section 3.2.1.2 describes the initial plant conditions for the at-power mode of operation; Section 3.2.1.3 describes the initial conditions; and Section 3.2.1.6 describes SFP initial conditions.

Guidance document NEI 12-06, Section 3.2.1.1 provides the acceptance criterion for the analyses serving as the technical basis for establishing the time constraints for the baseline coping capabilities to maintain SFP cooling. This criterion is keeping the fuel in the SFP covered with water.

The ELAP causes a loss of cooling in the SFP. As a result, the pool water will heat up and eventually boil off. The licensee's response is to provide makeup water. The timing of operator actions and the required makeup rates depend on the decay heat level of the fuel assemblies in the SFP. The sections below address the response during operating, pre-fuel transfer or post-fuel transfer operations. The effects of an ELAP with full core offload to the SFP is addressed in Section 3.11. Point Beach has one SFP shared by both units and is located in the PAB.

3.3.1 Phase 1

In the FIP, Section 3.3.1 states that the SFP temperature is allowed to increase to the boiling point; however, prior to boiling, hoses and fittings necessary for makeup or spray strategies are deployed on the SFP refueling deck. The SFP level is monitored using instrumentation installed as required by NRC Order EA-12-051 and water will be added well before fuel becomes uncovered. In addition, the ventilation for the PAB is provided by opening the truck access doors and personnel doors, as necessary, based on conditions.

3.3.2 Phase 2

In the FIP, Section 3.3.2 states that during Phase 2, makeup is initiated by using the hoses and fittings that were deployed into the SFP refueling deck during Phase 1. Makeup to the SFP can be provided by the FLEX PDSG pump through a distribution header to inject 50 gpm of flow to the SFP via a 2-1/2" connection point downstream of valve BS-350 on the suction of the P-9, hold up tank (HUT) recirculation pump without access to the SFP refueling deck.

Additionally, spray nozzles and sufficient hose length required for the SFP spray option are provided in designated FLEX job boxes in the waste gas compressor (WGC) room on the 44ft. elevation of the PAB. The 5" discharge hose from the FLEX PDLP pump is routed through the 8 ft. elevation of the TB and PAB where it connects to the 2-1/2" hoses that are routed to the SFP via a wye connection.

3.3.3 Phase 3

In the FIP, Section 3.3.3 states that the primary strategy in Phase 3 is to reestablish SW cooling flow to the SFP heat exchangers and provide power to the SFP pumps. The major equipment utilized in this strategy is the high capacity, low pressure pump and 4160 Vac CTGs supplied by the NSRC.

3.3.4 Staff Evaluations

3.3.4.1 Availability of Structures, Systems, and Components

3.3.4.1.1 Plant SSCs

Condition 6 of NEI 12-06, Section 3.2.1.3, states that permanent plant equipment contained in structures with designs that are robust with respect to seismic events, floods, and high winds, and associated missiles, are available. In addition, Section 3.2.1.6 states that the initial SFP conditions are: 1) all boundaries of the SFP are intact, including the liner, gates, transfer canals, etc.; 2) although sloshing may occur during a seismic event, the initial loss of SFP inventory does not preclude access to the refueling deck around the pool; and 3) SFP cooling system is intact, including attached piping.

The FIP sequence of events timeline indicates that operators will deploy the FLEX PDSG pump and route hose for SFP makeup at the P-9 connection within 4 hours from event initiation. Furthermore, it also indicates that operators will install nozzles and route hoses from the SFP refueling deck to the 8' elevation of the PAB to support the SFP spray option within 9 hours from event initiation. The PAB is a seismic Class 1 structure protected from the effects of tornados (see UFSAR Sections A.5.2 and 1.3.1); thus, it is expected that operators can accomplish FLEX activities within the structure during an ELAP event. The staff's evaluation regarding the robustness of these connections points, including access routes, are documented in SE Section 3.7.3. Otherwise, the licensee's SFP FLEX strategy does not rely upon any additional permanent plant equipment.

The licensee's Phase 2 SFP cooling strategy involves use of the FLEX PDSG or PDLP pumps with suction from the UHS, to supply water to the SFP for makeup or spray, respectively. The staff's evaluation of the robustness and availability of the UHS for an ELAP event is discussed in Section 3.10.3.

3.3.4.1.2 Plant Instrumentation

In its FIP, the licensee stated that the instrumentation for SFP level will meet the requirements of Order EA-12-051. Furthermore, the licensee stated that these instruments will have initial local battery power with the capability to be powered from the FLEX DGs. The NRC staff's review of the SFP level instrumentation, including the primary and back-up channels, the display to monitor the SFP water level and environmental qualifications to operate reliably for an extended period are discussed in Section 4 of this SE.

3.3.4.2 Thermal-Hydraulic Analyses

In the FIP, Section 3.3.4.2 states that with a loss of SFP cooling with the worst-case design heat load (full core offload) and an initial temperature of 145 °F, the time-to-boil is approximately 7 hours (See also UFSAR Section 9.9.3). The licensee indicated that this is very conservative considering it maintains SFP temperatures lower than 145 °F. The licensee explained that it tracks the SFP heat load on a real time basis and that based on typical SFP heat loading, and assuming a full core offload with an initial SFP temperature of 100°F, the projected time for the SFP to reach 200°F is approximately 11 hours. In the Point Beach UFSAR, Section 9.9.3 explains that a makeup water supply of 50 gpm is adequate to maintain SFP level at the worst-case design heat load. Thus, the staff concludes that it is reasonable that during non-outage situations the time-to-boil in the SFP will be greater than 11 hours and that a flow rate of 50gpm is sufficient to account for boil-off.

3.3.4.3 FLEX Pumps and Water Supplies

As discussed in SE Section 3.3.4.2, a makeup water supply of 50 gpm is adequate to maintain SFP level for the worst-case design heat load (full core offload). In the FIP, Section 3.3.4.3 states that water is added to the SFP with a portable diesel driven pump (PDSG or PDLP) using either direct addition or spray.

The licensee's Phase 2 strategy will use a distribution manifold that allows the FLEX PDSG pump to inject flow to the SFP for makeup while also providing flow to the SGs or use the PDLP pump to provide SFP spray. As previously discussed, the FLEX PDSG pump is a trailer-mounted, diesel driven engine, centrifugal pump rated for 325 gpm at 400 psig, and is stored in the FSB. A single FLEX PDSG pump has sufficient capacity to provide flow to the common SFP; thus, two FLEX PDSG pumps are available to satisfy the N+ 1 requirement. The PDLP pump is capable of providing 500 gpm of spray to the SFP and is rated at 1000 gpm at ~160 psig operating at 1800 rpm. A single PDLP pump can supply the common SFP; thus, two PDLP pumps are available to satisfy the N+1 requirement. These FLEX pumps (PDSG or PDLP) will draw raw water from the CWPH SW pump bay, forebay (directly or via the B.5.b standpipe) or direct draft from Lake Michigan.

As discussed in SE Section 3.2.3.5, hydraulic analysis, Calculation 2015-04238, "Hydraulic Analysis of Flow Path with the Supply of Lake Water to the SGs via the AFW System During a FLEX Scenario," August, 12, 2015, demonstrated that the FLEX PDSG pump rated at 325gpm at 400 psig can provide sufficient makeup to the SGs (both units) and to the SFP. Furthermore, FIP Section 3.3.4.3 indicates that the PDLP, which provides SFP spray during an ELAP event, is bounded by B.5.b hydraulic analysis, Calculation M-11165-090-FP.1, "Hydraulic Analysis of Flow Path to the Spent Fuel Pool During a B.5.b Scenario."

The licensee's Phase 3 strategy is to reestablish SW cooling flow to the SFP heat exchangers and provide power to the SFP pumps with the use of the high capacity, low pressure pump and 4160 Vac portable CTG supplied by the NSRC. In the FIP, Section 3.8 indicates that the low pressure-high capacity pump can remove heat from the reactor core in addition to other loads, including the SFP, and has a minimum flow capability of 5000 gpm at a working discharge pressure of 150 psig. The FIP also describes this pump as self-priming and capable of drawing 12 ft. suction at sea level. The pump suction will be the same as Phase 2, which is the CWPH pump bay, forebay or directly from Lake Michigan.

The staff concludes that the licensee's FLEX pumps (PDSG and PDLP) should have sufficient capacity to provide the necessary SFP makeup rate of 50 gpm and SFP spray rate of 250 gpm, respectively.

3.3.4.4 Electrical Analyses

The basic FLEX strategy for maintaining SFP cooling is to monitor the SFP level and provide makeup water to the SFP sufficient to maintain substantial radiation shielding for a person standing on the SFP refueling floor and provide for cooling for the spent fuel due to boil-off of the water.

The NRC staff performed a comprehensive analysis of the licensee's electrical strategies, which includes the SFP cooling strategy. The electrical components credited by the licensee as part of its FLEX mitigation strategies, outside of instrumentation to monitor SFP level (which is described in other areas of this SE), are high capacity, low pressure pump and 4160 Vac CTGs (including cables and connectors) that will be supplied by an NSRC. According to the licensee's FIP, these generators could be used to re-power SFP cooling systems, if necessary. The NRC staff reviewed calculation 2004-0002, and concludes that the 4160 Vac equipment being supplied from the NSRC has sufficient capacity and capability to supply power to the SFP systems, if necessary.

3.3.5 Conclusions

Based on this evaluation, the NRC staff concludes that the licensee has developed guidance that, if implemented appropriately, should maintain or restore SFP cooling following a BDBEE consistent with NEI 12-06, as endorsed by JLD-ISG-2012-01, and should adequately address the requirements of the order.

3.4 Containment Function Strategies

The industry guidance document, NEI 12-06, Table 3-2, provides some examples of acceptable approaches for demonstrating the baseline capability of the containment strategies to effectively maintain containment functions during all phases of an ELAP event. One such approach is for a licensee to perform an analysis demonstrating that containment pressure control is not challenged. The units each have a dry ambient pressure containment.

The licensee performed a containment evaluation, NAI-1761, Revision 1, which was based on the boundary conditions described in Section 2 of NEI 12-06. The calculation analyzed the strategy monitoring containment pressure and temperature and concluded that the containment parameters of pressure and temperature remain well below the respective UFSAR Section 5.1.1 design limits of 60 psig and 286°F for more than 48 hours. From its review of the evaluation, the NRC staff noted that the required actions to maintain containment integrity and required instrumentation functions have been developed, and are summarized below.

3.4.1 Phase 1

The Phase 1 coping strategy for containment involves verifying containment isolation as required and monitoring containment temperature and pressure using installed instrumentation. Containment pressure and temperature will be available via essential plant instrumentation. Containment isolation is verified in Events and Conditions Assessment (ECA) – 0.0, "Loss of All AC Power."

3.4.2 Phase 2

During Phase 2, containment pressure and temperature are monitored to ensure the containment safety function is not challenged. If containment conditions warrant, a PDLP pump will supply water to the CS system via an adapter that will replace the cover of a CS pump discharge check valve, 1(2)SI-862A/B. This strategy is currently applied in the plant B.5.b response. Lake Michigan water is the primary source for cooling water. Procedure FSG-5.4 provides guidance for low pressure diesel pump collections and operation.

In Modes 5 and 6, SEP 3.0 requires containment closure to be established unless a containment vent path is required for the ELAP condition.

FSG-12, Alternate Containment Cooling, provides the following containment vent paths:

- The primary method for venting the containment is by opening containment hatch doors.

Alternate methods include:

- Vent the containment via the deflated T-ring seal on containment supply and exhaust dampers.
- Vent the containment using hydrogen recombiner valves 1H2-V -4 and 1H2-V-5 or 1H2-V-22 and 1H2-V-23.

3.4.3 Phase 3

The strategies implemented during Phase 2 are capable of maintaining containment for an indefinite amount of time. The Phase 3 equipment from the NSRCs is capable of supporting these functions should the Phase 2 equipment need to be replaced.

Phase 3 equipment has sufficient capacity to provide additional defense in depth by recovering normal containment heat removal capabilities. Actions to reduce containment temperature and pressure and to ensure continued functionality of the key parameters, if necessary, will utilize existing plant systems restored by off-site equipment and resources during Phase 3. Phase 3 equipment can restore power to the containment cooling fans and cooling water flow to the containment fan coolers.

FSG-12, Alternate Containment Cooling, provides options for establishing containment cooling:

- Alternate power to containment fan and cooling water;
- Alternate power to contaiment spray pump;
- Portable diesel driven pump to containment spray;
- Containment purge for venting/cooling.

3.4.4 Staff Evaluations

3.4.4.1 Availability of Structures, Systems, and Components

Guidance document NEI 12-06 baseline assumptions have been established on the presumption that other than the loss of the ac power sources and normal access to the UHS, installed equipment that is designed to be robust with respect to design-basis external events is assumed to be fully available. Installed equipment that is not robust is assumed to be unavailable. Below are the baseline assumptions for the availability of SSCs for maintaining containment functions during an ELAP.

3.4.4.1.1 Plant SSCs

Containment Spray and Containment Spray Pumps

The Point Beach UFSAR indicates the containment spray system is engineered safety system designed to remove containment heat following a LOCA or main steam line break. The system is designed, constructed, and installed to withstand the effects of a seismic event and is protected from tornado missiles.

Containment Fan and Cooling Water

The Point Beach UFSAR indicates that the containment air recirculation cooling system is an engineered safety system designed to remove containment heat following a LOCA or main steam line break. The system is designed, constructed, and installed to withstand the effects of a seismic event and is protected from tornado missiles.

Containment Purge

The containment purge system is isolated and blank flanged during operation. The containment penetration is designed to withstand the effects of a seismic event and is protected from tornado missiles. The containment purge system is only credited for containment venting during Modes 5 and 6.

3.4.4.1.2 Plant Instrumentation

In NEI 12-06, Table 3-2, specifies that containment pressure is a key containment parameter which should be monitored by repowering the appropriate instruments. The licensee's FIP states that control room instrumentation would be available due to the coping capability of the station batteries and associated inverters in Phase 1, or the portable DGs deployed in Phase 2. If no ac or dc power is available, the FIP states that key credited plant parameters, including containment pressure, would be available using alternate methods. Procedure FSG-12, "Alternate Containment Cooling," provides guidance regarding plant instrumentation for monitoring containment temperature, pressure, and radiation. Procedure FSG-7, "Loss of Vital Instrumentation or Control Power," provides guidance to monitoring containment parameters when instrumentation is not powered.

3.4.4.2 Thermal-Hydraulic Analyses

Calculation NAI-1761-004, "Point Beach Containment Response for ELAP with Cooldown," Revision 1, used the GOTHIC (Generation of Thermal Hydraulic Information for Containments). The calculation assumes that the RCP seal leakage to be 1 gpm per pump and an RCS technical specification allowed leak rate of 1 gpm. The calculation assumed no solar heat loads on the containment structure as the containment is enclosed within a facade. The calculation assumes a constant ambient temperature of 105.5°F.

The calculation concludes that the containment temperature will be 148°F and containment pressure will be 17.2 psia at approximately 2 days (175,000 seconds) following ELAP. This is below the design limits of 286 degrees °F and 75 psia (60 psig). The calculation does not address containment conditions beyond 175,000 seconds.

During the audit, NRC staff requested justification for limiting the containment analysis to 175,000 seconds (2 days). The licensee indicated that engineering judgment was used to arrive at the value of 2 days based on decreasing decay heat loads and a linear extrapolation of the calculation results, which demonstrated that the temperature would not increase enough to challenge containment design limits. Furthermore, it is their intention to use Phase 3 equipment to energize containment cooling as needed.

3.4.4.3 FLEX Pumps and Water Supplies

In the FIP, Section 3.4 states that low leakage RCP seals for both units have been installed and will prevent significant leakage from the RCS seals into containment. The licensee explained that a FLEX containment analysis based on the use of low leakage RCP seals determined that approximately 2 days after the ELAP initiating event, the containment pressure will reach of value of 17.2 psia and temperature will reach 148° F, which are significantly less than the design limits of 75 psia and 286° F. During Phase 2, the licensee will monitor the containment pressure and temperature to ensure the containment is not challenged; however, it is not expected that the design containment pressure and temperature will be challenged before additional resources arrive from off-site. If necessary, a PDLP pump can supply water to the CS system via an adapter that will replace the cover of a CS pump discharge check valve, 1(2)SI-862A/B.

In the FIP, Section 3.4.4.3 states that the PDLP pump is used for containment spray to provide containment cooling, if necessary. The FIP describes that the PDLP may be aligned with the SW pump bay, forebay or Lake Michigan and is rated at 1000 gpm at ~160 psig operating at 1800 rpm. The PDLP pump is a diesel engine driven pump that is stored in the FSB. A single PDLP pump has sufficient capacity to provide water for containment spray to both units; thus, two PDLP pumps are available to satisfy the N+1 requirement.

The staff concludes that the licensee's containment integrity strategies do not rely on the use of FLEX pumps and water sources for maintaining containment pressure or temperature below the design limits for at least 72 hours. At this time, additional staffing and equipment from the NSRC will be available to the licensee to establish containment cooling by repowering installed equipment with portable generators or using portable pumps to provide water to the CS system.

3.4.4.4 Electrical Analyses

The licensee performed a containment evaluation based on the boundary conditions described in Section 2 of NEI 12-06. Based on the results of this analysis, the licensee developed required actions to ensure maintenance of containment integrity and functionality of required instrumentation. With an ELAP initiated, while either unit is in Modes 1-4, containment cooling for that unit is also lost for an extended period of time. Therefore, containment temperature and pressure will slowly increase. Structural integrity of the reactor containment building due to increasing containment pressure will not be challenged during the first several weeks of an ELAP event. However, with no cooling in the containment, temperatures in the containment are expected to rise and could reach a point where continued reliable operation of key instrumentation might be challenged. In calculation NAI-1761-004, "Point Beach Containment Response for ELAP with Cooldown," Revision 0, the licensee determined that peak containment temperature and pressure is expected to reach 148˚F and 17.2 psia approximately 2 days into an ELAP event which are both below the containment design temperature limits of 286˚F and 75 psia. During the onsite audit, the NRC staff confirmed that based on decreasing decay heat loads, temperature should not increase enough to challenge containment design limits even beyond 2 days.

The licensee's Phase 1 coping strategy for containment involves initiating and verifying containment isolation in accordance with ECA-0.0, "Loss of All AC Power." These actions ensure containment isolation following an ELAP event. Phase 1 also includes monitoring containment temperature and pressure using installed instrumentation. Control room indication for containment pressure and containment temperature is available for the duration of the ELAP event.

The licensee's Phase 2 coping strategy is to continue monitoring containment temperature and pressure using installed instrumentation to ensure containment safety functions are not challenged. In its FIP, the licensee stated that the Phase 2 strategies are capable of maintaining containment for an indefinite amount of time.

The licensee stated that the Phase 3 strategy is focused on providing defense-in-depth and recovery of containment normal heat removal capabilities and to ensure continued functionality of key instrumentation and components utilizing existing plant systems restored by off-site equipment and resources. The primary strategy in Phase 3 is to restore power to the containment cooling fans and cooling water flow to the containment fan coolers. Specifically, the licensee would utilize two 1 MW, 4160 Vac CTGs and a distribution panel per unit, which will be brought in from an NSRC within 24 hours after requested to supply power to either of the two Class 1E 4160 Vac buses on each unit, if necessary. Additionally, by restoring the Class 1E 4160 Vac bus, power can be restored to the Class 1E 480 Vac buses via the 4160/480 Vac transformers to power selected 480 Vac loads.

The staff reviewed the licensee's calculation 2004-0002 and concludes that the Phase 2 electrical equipment available onsite (i.e. 480 Vac FLEX PDG) supplemented with the electrical equipment supplied from the NSRC (i.e., 480 Vac and 4160 Vac CTGs) should have sufficient capacity and capability to supply power to the required loads to reduce containment temperature and pressure, if necessary, and to ensure that key instrumentation and components remain functional.

3.4.5 Conclusions

Based on this evaluation, the NRC staff concludes that the licensee has developed guidance that, if implemented appropriately, should maintain or restore containment functions following a BDBEE consistent with NEI 12-06, as endorsed by JLD-ISG-2012-01 and should adequately address the requirements of the order.

3.5 Characterization of External Hazards

Sections 4 through 9 of NEI 12-06 provide the methodology to identify and characterize the applicable BDBEEs for each site. In addition, NEI 12-06 provides a process to identify potential complicating factors for the protection and deployment of equipment needed for mitigation of applicable site-specific external hazards leading to an ELAP and loss of normal access to the UHS.

Characterization of the applicable hazards for a specific site includes the identification of realistic timelines for the hazard, characterization of the functional threats due to the hazard, development of a strategy for responding to events with warning, and development of a strategy for responding to events without warning.

The licensee reviewed the plant site against NEI 12-06 and determined that FLEX equipment should be protected from the following hazards: seismic; external flooding; severe storms with high winds; snow, ice and extreme cold; and extreme high temperatures.

References to external hazards within the licensee's mitigating strategies and this SE are consistent with the guidance in NEI-12-06 and the related NRC endorsement of NEI 12-06 in JLD-ISG-2012-01. Guidance document NEI 12-06 directed licensees to proceed with evaluating external hazards based on currently available information. For most licensees, this meant that the OIP used the current design-basis information for hazard evaluation. Coincident with the issuance of Order EA-12-049, on March 12, 2012, the NRC staff issued a Request for Information pursuant to Title 10 of the *Code of Federal Regulations* Part 50, Section 50.54(f) (ADAMS Accession No. ML12053A340) (hereafter referred to as the 50.54(f) letter), which requested that licensees reevaluate the seismic and flooding hazards at their sites using updated hazard information and current regulatory guidance and methodologies. Due to the time needed to reevaluate the hazards, and for the NRC to review and approve them, the reevaluated hazards were generally not available until after the mitigation strategies had been developed. The NRC staff has developed a proposed rule, titled "Mitigation of Beyond-Design-Basis Events," hereafter called the MBDBE rule, which was published for comment in the Federal Register on November 13, 2015 (*Federal Register*, Vol. 80, No. 219, November 13, 2015, pp. 70610-70647). The proposed MBDBE rule would make the intent of Orders EA-12-049 and EA-12-051 generically applicable to all present and future power reactor licensees, while also requiring that licensees consider the reevaluated hazard information developed in response to the 50.54(f) letter.

The NRC staff requested Commission guidance related to the relationship between the reevaluated flooding hazards provided in response to the 50.54(f) letter and the requirements for Order EA-12-049 and the MBDBE rulemaking (see COMSECY-14-0037, Integration of Mitigating Strategies for Beyond-Design-Basis External Events and the Reevaluation of Flooding Hazards" (ADAMS Accession No. ML14309A256). The Commission provided guidance in an SRM to COMSECY-14-0037 (ADAMS Accession No. ML15089A236). The Commission approved the staff's recommendations that licensees would need to address the reevaluated flooding hazards within their mitigating strategies for BDBEEs, and that licensees may need to address some specific flooding scenarios that could significantly damage the power plant site by developing scenario-specific mitigating strategies, possibly including unconventional measures, to prevent fuel damage in reactor cores or SFPs. The NRC staff did not request that the Commission consider making a requirement for mitigating strategies capable of addressing the reevaluated flooding hazards be immediately imposed, and the Commission did not require immediate imposition. In a letter to licensees dated September 1, 2015 (ADAMS Accession No. ML15174A257), the NRC staff informed the licensees that the implementation of mitigation strategies should continue as described in licensee's OIPs, and that the NRC safety evaluations and inspections related to Order EA-12-049 will rely on the guidance provided in JLD-ISG-2012-01, Revision 0, and the related industry guidance in NEI 12-06, Revision 0. The hazard reevaluations may also identify issues to be entered into the licensee's corrective action program consistent with the OIPs submitted in accordance with Order EA-12-049.

As discussed above, licensees are reevaluating the site seismic and flood hazards as requested in the NRC's 50.54(f) letter. After the NRC staff approves the reevaluated hazards, licensees will use this information to perform flood and seismic mitigating strategies assessments (MSAs) per the guidance in NEI 12-06, Revision 2, Appendices G and H (ADAMS Accession No. ML16005A625). The NRC staff endorsed Revision 2 of NEI 12-06 in JLD-ISG-2012-01, Revision 1 (ADAMS Accession No. ML15357A163). The licensee's MSAs will evaluate the mitigating strategies described in this SE using the revised flooding and seismic hazard information and, if necessary, make changes to the strategies or equipment. Licensees will submit the MSAs for NRC staff review.

The licensee developed its OIP for mitigation strategies by considering the guidance in NEI 12-06 and the site's design-basis hazards. Therefore, this SE makes a determination based on the licensee's OIP and FIP. The characterization of the applicable external hazards for the plant site is discussed below.

3.5.1 Seismic

In its FIP, the licensee described the current design-basis seismic hazard, the SSE. As described in the Point Beach UFSAR, Appendix A.5, "Seismic Design Analysis," the SSE seismic criteria for the site is 0.12g horizontal ground motion with a simultaneous vertical acceleration of 2/3 of the magnitude of the horizontal. It should be noted that the actual seismic hazard involves a spectral graph of the acceleration versus the frequency of the motion. Peak acceleration in a certain frequency range, such as the numbers above, is often used as a shortened way to describe the hazard.

As the licensee's seismic reevaluation activities are completed, the licensee is expected to assess the mitigation strategies to ensure they can be implemented under the reevaluated hazard conditions as will potentially be required by the proposed MBDBE rulemaking. The licensee has appropriately screened in this external hazard and identified the hazard levels to be evaluated.

3.5.2 Flooding

In its FIP, the licensee stated that the Point Beach licensing basis level for protection of critical equipment from lake flooding is +9.0 ft. The bounding external flooding event can be either a maximum wave run-up event from Lake Michigan or a maximum precipitation event. There are no rivers or large streams at or near Point Beach. As stated in the licensee's OIP, assuming conservatively that the maximum wave height occurs simultaneously with the maximum Lake Michigan level, the run-up would be to the elevation +8.42 ft. on a vertical structure. In addition, the licensee noted in its FIP that there is a potential of an internal flooding event due to the failure of a non-seismic tank or non-seismic service water piping during an earthquake. However, the licensee stated that the water would collect in the -19 ft. elevation of the PAB, in which all of the PAB connections are above this elevation.

As the licensee's flooding reevaluation activities are completed, the licensee is expected to assess the mitigation strategies to ensure they can be implemented under the reevaluated hazard conditions as will potentially be required by the proposed Mitigation of Beyond Design Basis Events rulemaking. The licensee has appropriately screened in this external hazard and identified the hazard levels to be evaluated.

3.5.3 High Winds

In NEI 12-06, Section 7, provides the NRC-endorsed screening process for evaluation of high wind hazards. This screening process considers the hazard due to hurricanes and tornadoes.

The screening for high wind hazards associated with hurricanes should be accomplished by comparing the site location to NEI 12-06, Figure 7-1 (Figure 3-1 of U.S. NRC, "Technical Basis for Regulatory Guidance on Design Basis Hurricane Wind Speeds for Nuclear Power Plants," NUREG/CR-7005, December, 2009); if the resulting frequency of recurrence of hurricanes with wind speeds in excess of 130 mph exceeds 1E-6 per year, the site should address hazards due to extreme high winds associated with hurricanes using the current licensing basis for hurricanes.

The screening for high wind hazard associated with tornadoes should be accomplished by comparing the site location to NEI 12-06, Figure 7-2, from U.S. NRC, "Tornado Climatology of the Contiguous United States," NUREG/CR-4461, Rev. 2, February 2007; if the recommended tornado design wind speed for a 1E-6/year probability exceeds 130 mph, the site should address hazards due to extreme high winds associated with tornadoes using the current licensing basis for tornados or Regulatory Guide 1.76, Rev. 1.

Point Beach's UFSAR states that the site is located at 44° 17.0' North latitude and 87° 32.5' West longitude. In NEI 12-06 Figure 7-2, Recommended Tornado Design Wind Speeds for the 1E-6/year Probability Level indicates the site is in Region 1, where the tornado design wind speed exceeds 130 mph. Therefore, the plant screens in for an assessment for high winds and tornados, including missiles produced by these events. Although the licensee did not address the impact of a hurricane in the integrated plan, the site is beyond the range of high winds from a hurricane per NEI 12-06 Figure 7-1. The NRC staff concludes that a hurricane hazard is not applicable and need not be addressed.

Therefore, high-wind hazards are applicable to the plant site. The licensee has appropriately screened in the high wind hazard and characterized the hazard in terms of wind velocities and wind-borne missiles.

3.5.4 Snow, Ice, and Extreme Cold

As discussed in NEI 12-06, Section 8.2.1, all sites should consider the temperature ranges and weather conditions for their site in storing and deploying FLEX equipment consistent with normal design practices. All sites outside of Southern California, Arizona, the Gulf Coast and Florida are expected to address deployment for conditions of snow, ice, and extreme cold. All sites located north of the 35th Parallel should provide the capability to address extreme snowfall with snow removal equipment. Finally, all sites except for those within Level 1 and 2 of the maximum ice storm severity map contained in Figure 8-2 should address the impact of ice storms.

Point Beach's UFSAR states that the site is located at 44° 17.0' North latitude and 87° 32.5' West longitude. In addition, the site is located within the region characterized by Electric Power Research Institute (EPRI) as ice severity Region 5 (NEI 12-06, Figure 8-2, Maximum Ice Storm Severity Maps). Consequently, the site is subject to severe icing conditions that could cause severe damage to electrical transmission lines. The licensee concludes that the plant screens in for an assessment for snow, ice, and extreme cold hazard.

In summary, based on the available local data and Figures 8-1 and 8-2 of NEI 12-06, the plant site does experience significant amounts of snow, ice, and extreme cold temperatures; therefore, the hazard is screened in. The licensee has appropriately screened in the hazard and characterized the hazard in terms of expected temperatures.

3.5.5 Extreme Heat

In the section of its FIP regarding the determination of applicable extreme external hazards, the licensee stated that, as per NEI 12-06 Section 9.2, all sites are required to consider the impact of extreme high temperatures. Summers at the site may bring periods of extremely hot weather over 100 °F. The plant site screens in for an assessment for extreme high temperature hazard.

In summary, based on the available local data and the guidance in Section 9 of NEI 12-06, the plant site does experience extreme high temperatures. The licensee has appropriately screened in the high temperature hazard and characterized the hazard in terms of expected temperatures.

3.5.6 Conclusions

Based on the evaluation above, the NRC staff concludes that the licensee has developed a characterization of external hazards that is consistent with NEI 12-06, as endorsed by JLD-ISG-2012-01, and should adequately address the requirements of the order.

3.6 Planned Protection of FLEX Equipment

3.6.1 Protection from External Hazards

The FLEX equipment is stored in existing Class 1 structures or in the north half of the Steam Generator Storage Building (SGSB), which has been upgraded to qualify as the FLEX Storage Building (FSB). It is a concrete structure located just north of Point Beach and directly outside of the security fence. The FSB is used as the primary storage location for essential FLEX equipment. In addition, debris removal/tow trucks are stored inside the FSB in order to be protected from the applicable external events such that the equipment will remain functional and deployable to clear obstructions from the pathway between the equipment's storage location and its deployment location. Below are additional details on how FLEX equipment is protected from each of the applicable external hazards.

3.6.1.1 Seismic

As stated above, the FLEX equipment is stored in existing Class 1 structures or the FSB. In its FIP, the licensee stated that the FSB has been analyzed for 2X seismic loading to qualify it for FLEX purposes. In addition, the stored FLEX portable equipment will be secured as required and protected from seismic interactions to ensure they are not damaged from unsecured and/or non-seismic components.

3.6.1.2 Flooding

In its OIP, the licensee stated that assuming conservatively that the maximum wave height occurs simultaneously with the maximum Lake Michigan level, the run-up would be to the elevation +8.42 ft. on a vertical structure. As stated in the FIP, the FSB is located at approximately the 31 ft. plant elevation and it is adjacent to topography which slopes to Lake Michigan. Thus, the FSB is not susceptible to flooding events. In addition, Point Beach has procedures in place to address Lake Michigan induced flooding.

3.6.1.3 High Winds

As discussed above, the north half of the SGSB has been upgraded to protect FLEX equipment from the applicable hazards defined in NEI 12-06. However, the south end is not fully protected since the west wall is a 2 ft. thick block wall that was not designed for tornado wind loads. In its FIP, the licensee stated that the CAT wheel loader will be stored in the south end of the SGSB. In the event of a failure of the wall, and to maintain the capability to remove debris, the loader is parked facing the west wall. In addition, since the CAT wheel loader is not fully protected, an alternate piece of debris removal equipment is located on the south end of the site at a sufficient distance (~1800 ft.) to prevent a tornado from impacting both.

3.6.1.4 Snow, Ice, Extreme Cold and Extreme Heat

On page 3 of its OIP, the licensee stated that regional experience with high temperatures does exist for Point Beach. In DBD-29 "Auxiliary Building and Control Building ['heating ventilation and air conditioning] HVAC" specifies a summer temperature of 95°F. Point Beach UFSAR Figure 2.6-1 "Climate of Point Beach Site Region," shows a max temperature of greater than 100°F. The current 50 year high is 105.5°F per (American Society of Heating, Refrigerating and Air Conditioning Engineers) ASHRAE 1 percent data (1 percent of the hours, 7 hours, in 1 month of 50 years exceed that value) with an average temperature swing of approximately 17°F in the hottest months. Based on the previous information, Point Beach used 105°F or greater in calculations for extreme environmental conditions. However, portable FLEX equipment was selected to operate in conditions for a maximum temperature of 110°F. In addition, the licensee stated that the FSB has ventilation to maintain temperatures within equipment manufacturers' recommendations.

Regional experience with snow, ice and low temperatures does exist for Point Beach. From Figure 8.2 of NEI 12-06, the Point Beach location falls under Region 5, corresponding to the highest region for ice severity. Per the Point Beach UFSAR, snowfall averages 45 inches per year with a maximum of 15 inches in 24 hours recorded in January 1947. Ice storms are infrequent in this region of Wisconsin. The hazard would include frost, ice cover, frazil ice, snow and extreme low temperature. It does not include an avalanche for the site. An outside air temperature of -25.0°F has been used in the Point Beach design. Design Basis Document (DBD)-29, "Auxiliary Building and Control Building HVAC," specifies a winter temperature of -15°F. Point Beach UFSAR Figure 2.6-1, "Climate of Point Beach Site Region," shows a minimum temperature of less than -20°F. The current 50 year low is -28.1 °F per the American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) 1 %data (1 % of the hours, 7 hours, in a month of 50 years exceed that value). The average temperature swing is approximately 12° F in the coldest months. For FLEX equipment, a minimum temperature of

-28 °F is used for design. Procedure guidance is provided for starting FLEX equipment operated outdoors in cold weather conditions.

3.6.2 Reliability of FLEX Equipment

Section 3.2.2 of NEI 12-06 states, in part, that in order to assure reliability and availability of the FLEX equipment, the site should have sufficient equipment to address all functions at all units on-site, plus one additional spare (i.e., an N+1 capability, where "N" is the number of units on site). It is also acceptable to have a single resource that is sized to support the required functions for multiple units at a site (e.g., a single pump capable of all water supply functions for a dual unit site). In this case, the N+1 could simply involve a second pump of equivalent capability. In addition, it is also acceptable to have multiple strategies to accomplish a function, in which case the equipment associated with each strategy does not require an additional spare.

Based on the number of portable FLEX pumps, FLEX DGs, and support equipment identified in the FIP and during the audit review, the NRC staff concludes that, if implemented appropriately, the licensee's FLEX strategies include a sufficient number of portable FLEX pumps, FLEX DGs, and equipment for RCS make-up and boration, SFP make-up, and maintaining containment consistent with the N+1 guidance in Section 3.2.2 of NEI 12-06.

3.6.3 Conclusions

Based on this evaluation, the NRC staff concludes that the licensee has developed guidance that, if implemented appropriately, should protect the FLEX equipment during a BDBEE consistent with NEI 12-06 guidance as endorsed by JLD-ISG-2012-01, and should adequately address the requirements of the order.

3.7 Planned Deployment of FLEX Equipment

The licensee stated in its FIP that preferred and alternate haul paths have been identified and documented in the FSGs. Figure 3.7.1 of the FIP shows the haul paths from the FSB to the various deployment locations. These haul paths have been reviewed for potential soil liquefaction and, in summary, have been determined to be stable following a seismic event.

3.7.1 Means of Deployment

The deployment of onsite FLEX equipment to implement coping strategies beyond the initial plant capabilities (Phase 1) requires that pathways between the FSB and various deployment locations be clear of debris resulting from seismic, high wind (tornado), or flooding events. The stored FLEX equipment includes tow vehicles with plows and a wheel loader to move or remove debris from the needed travel paths.

The gate and vehicle barrier in the route will be manually opened by Security in accordance with existing instructions for B.5.b deployment. Security doors and gates that rely on electric power to operate opening and/or locking mechanisms can be overridden by manual key locks; security and operations personnel have keys and the training necessary to open doors and gates during an ELAP event to allow access to implement the Point Beach FLEX strategies. Redundant keys are also available.

The preferred route is through an open non-forested area. However, this route does have an overhead ac service line along a portion of the path. If the line is down across the path, it will be disconnected from its supply power but considered potentially energized. It will be moved using debris removal and electrical safety equipment. Also, warehouses and buildings which are not designed for seismic or tornado wind loads exist alongside the deployment route. Debris along the route will be removed using designated FLEX debris removal equipment. As stated above, the debris removal equipment is stored inside the FSB, which protects the equipment from severe storm and high wind hazards such that the equipment remains functional and deployable to clear obstructions from the pathway between the FSB and its deployment location(s).

Phase 3 of the FLEX strategies involves the receipt of equipment from offsite sources including the NSRC and various commodities such as fuel and supplies. Transportation of these deliveries can be through airlift or via ground transportation. Debris removal for the pathway between the site and the receiving locations for Point Beach and from the various plant access routes may be required. The same debris removal equipment used for on-site pathways will be used to support debris removal to facilitate road access to the site.

3.7.2 Deployment Strategies

In its FIP, the licensee stated that the haul paths were reviewed for potential soil liquefaction. The soil liquefaction analysis concluded that liquefaction stability failure of the deployment path is highly unlikely regardless of the magnitude of the earthquake at Point Beach. The licensee stated that this conclusion was based on studies performed in support of the Point Beach IPEEE response and studies performed in relation to the Point Beach Independent Spent Fuel Storage Installation (ISFSI). During the onsite audit, the NRC staff reviewed documents Wisconsin Electric Letter VPNPD-95-056, "Summary Report on Individual Plant Examination of External Events for Severe Accident Vulnerabilities Point Beach Nuclear Plant, Units 1 and 2," dated June 30, 1995, "Point Beach Nuclear Plant 10 CFR 72.212 Evaluation Report for NUHOMs- 32 PT System," Revision 13, dated May 24, 2012, and "Point Beach Nuclear Plant 10CFR72.212 Evaluation Report for VSC-24 System," Revision 5, dated June 11, 2010, to verify the licensee's conclusions, and the NRC staff believes that liquefaction should not inhibit the necessary equipment deployment after an earthquake.

For the RCS cooling strategy, the PDSG pump provides the backup for the TDAFW pump during Phase 2. The PDSG pump will be staged near the CWPH taking suction from the SW pump bay located inside the seismic Category I, tornado missile protected CWPH. In the case where the CWPH SW pump bay or forebay are unavailable, the PDSG pump will be deployed to obtain suction via direct draft from Lake Michigan, which provides an indefinite supply of water for RCS cooling and heat removal with flow directly to the suction of the PDSG pump. Regarding RCS makeup, the PDCP pumps are staged on the 8 ft. elevation of the PAB taking suction from the seismic Class I RWST's.

For SFP make-up, the PDLP pump will be deployed to a location near the CWPH taking suction from the SW pump bay.

For the electrical strategy, a single FLEX 480 VAC generator for both units is deployed to the west side of the roadway between the TB and CWPH. The alternate location is outside the boiler room on the Northwest side of the plant.

3.7.3 Connection Points

3.7.3.1 Mechanical Connection Points

Core Cooling – Primary and Alternate Discharge Connection

In the FIP, Section 3.2.2.1.1 states that the seismically-designed primary discharge connection for the FLEX PDSG pump is located on the MDAFW pump cross connect line on the 8 ft. elevation of the PAB. The licensee explained that a 10 ft long hose is routed from the FLEX PDSG discharge manifold on the 8 ft elevation of the PAB to a hose adapter installed on the flange connection downstream of AF-201, which supports symmetric flow to the SGs in both units. Furthermore, in the event that the primary discharge connection for the FLEX PDSG is not available, the alternate discharge connection for SG injection is located at the B.5.b connections at valves 1(2)CS-303/304, which also supports symmetric flow to both SGs, that can be accessed from the 8 ft. elevation of the TB. In the UFSAR, Section A.5.2 indicates that the PAB (except for steel superstructure) is a seismic Class I structure. In UFSAR Section 10.2.5 it states the TB was analyzed during the original design and is capable of withstanding SSE loads. in UFSAR Section 1.3.1 it states that the seismic Class I portions of the PAB and TB is designed to withstand the effects of a tornado, which include wind force, pressure differential, and missile impingement. The licensee stated that external flooding has also been evaluated and determined not to have any adverse effects for the primary connection points in Engineering Evaluation 2015-0016, "LIP Flooding Coping Strategies (Flood Levels) EC 284296." Thus, the staff concludes that at least one of the connect points should be available to support the core cooling FLEX strategies during an ELAP event, consistent with NEI 12-06, Section 3.2.2 and Table D-1.

RCS Inventory Control – Primary and Alternate Discharge Connection

In the FIP, Section 3.2.2.1.1 states that the primary and alternate connection points for the PDCP are downstream of valves 1(2)CV-262B/E and 1(2)CV-262C/F, respectively, and both are located on the 8 ft elevation of the PAB. The licensee explained that these connections are located on CVCS piping that provides a closed loop outside containment; therefore, they are seismically-analyzed. The licensee stated that the discharge locations are isolable such that a failure of one of the connections does not disable the other connection and its ability to feed either RCS loop. As discussed above, the PAB is a seismic Class I structure capable of withstanding the effects of a tornado and these connection points were determined to not be adversely impacted by external flooding in Engineering Evaluation 2015-0016, "LIP Flooding Coping Strategies (Flood Levels) EC 284296." Due to the design and location of the primary and alternate RCS injection connection points, as described in the FIP, consistent with NEI 12-06, Section 3.2.2 and Table D-1, at least one of the diverse connection points should be available to support RCS injection during an ELAP event.

SFP Cooling – Primary and Alternate Discharge Connections

In the FIP, Section 3.3.4.1.1 states that the seismically robust primary makeup connection is located on the 8 ft. elevation of the PAB and is downstream of valve BS-350 on the suction of the P-9, HUT recirculation pump, that will allow the addition of raw water from the FLEX PDSG to the SFP without accessing the refueling deck. The licensee also explained that the alternate makeup connection uses a spray option by providing flow through two portable spray nozzles clamped to the SFP handrail on the refueling deck through two hoses routed from the PDLP pump. The staff noted that the discharge hose can be used to provide makeup directly to the SFP instead of using the spray nozzles. As discussed above, the PAB is a seismic Class I structure capable of withstanding the effects of a tornado, and these connection points were determined to not be adversely impacted by external flooding in Engineering Evaluation 2015-0016, "LIP Flooding Coping Strategies (Flood Levels) EC 284296." The licensee explained that all equipment used for the SFP spray strategy after the discharge of the PDLP pump is stored in metal FLEX storage boxes in the WGC room on the 44 ft. elevation of the PAB, in addition to the FLEX hose trailer that is also equipped with two spray nozzles. Thus, the staff concludes that the equipment downstream of the PDLP is protected from the external hazards and should be available to support the licensee's FLEX strategies. In addition, the staff concludes that the available connection points (including the associated hoses/spray nozzles) in the licensee's SFP cooling FLEX strategies appear to be consistent with the baseline capabilities identified in NEI 12-06, Section 3.2.2 and Table D-3 and at least one connection point should be available during an ELAP event.

Containment Cooling – Primary and Alternate Discharge Connections

In the FIP, Section 3.4.4 states that the seismically robust primary and secondary makeup connections are located in the 8 ft. elevation of the PAB on the CS system via an adapter that will replace the cover of a CS pump discharge check valve, 1(2)SI-862A/B. As discussed above, the PAB is a seismic Class I structure capable of withstanding the effects of a tornado and these connection points were determined to not be adversely impacted by external flooding in Engineering Evaluation 2015-0016, "LIP Flooding Coping Strategies (Flood Levels) EC 284296." Thus, the staff concludes that at least one of the connection points should be available during an ELAP event, consistent with NEI 12-06, Table D-2.

3.7.3.2 <u>Electrical Connection Points</u>

In its FIP, the licensee stated that a single FLEX 480 Vac DG would be staged and deployed to the west side of the roadway between the TB and CWPH during an ELAP event. The alternate staging location is outside by the heating boiler room. The primary connection points for the FLEX 480 Vac portable DG is at safeguards buses 1B-03 and 2B-03. These buses are located on the 26 ft. elevation of the cable spreading room inside the control building, a seismic Class I and missile protected structure. The elevation of the connection exceeds the elevation associated with external flood levels and design features protect this area from internal flooding. Initially, three cables (1 per phase) would be routed from the DG to FLEX breaker inserts at 1B-03 and 2B-03. The Phase 2 secondary 480 Vac electrical connections are at safeguards MCCs 1(2) B-32 and 1(2) B-42. These secondary connections are located in the PAB.

Regarding the Phase 2 alternate 480 Vac electrical connections, the alternate FLEX DG location is outside the boiler room on the Northwest side of the plant. The alternate connection points for the FLEX 480 Vac DG is at safeguards MCCs 1(2) B-32 and 1(2) B-42. These buses are located in the cable spreading room inside the control building. Also, the secondary connections for the battery chargers are at MCCs 1(2) B-39 and 1(2) B-49 which are located in the vital switchgear room which is part of the control building. Therefore, the connections are located in a seismic Category I structure and are missile protected. Licensee procedures FSG 5, "Initial Assessment and FLEX Equipment Staging," Revision 0, FSG 5.2, "FLEX Equipment Staging," Revision 0, and FSG 5. 3, "FLEX Electrical Operation," Revision 0, provide guidance to the operators to stage, deploy, connect and operate Phase 2 FLEX equipment. FSG 5.3 also provides guidance on how to verify the Phase 2 PDG phase rotation and, if necessary, correct the rotation by swapping two wires at the breaker inserts.

The Phase 3 4160 Vac NSRC CTGs will be located near the G-03/G04 DG building on the north side of the plant at the 28 ft. elevation. Additionally, by restoring the Class 1E 4160 Vac bus, power can be restored to the Class 1E 480 Vac buses via the 4160/480 Vac transformers to power selected 480 Vac loads. The primary connection point for the FLEX 4160 Vac CTGs supplied by the NSRC is at the 1(2) A-06, 4160 Vac switchgear located in the G-03/G-04 building. Cables from the CTGs will be routed to the G-03/G-04 building and connected at 4160 Vac Bus 1A-06, Breakers 1A52-77, 1A52-80 or 1A52-86 and 2A-06, Breakers 2A52-90, 2A52-94 or 2A52- 95. This is a safety-related, seismic structure that provides missile protection for this connection. Licensee procedures FSG-5 and FSG-5.7, "FLEX NSRC Equipment Operation," Revision 0, provide guidance to the operators to stage, connect, and operate Phase 3 NSRC equipment. Step 1.4 of FSG 5.7 provides guidance on how to verify proper phase rotation of the NSRC CTG connections before switchgears are energized.

3.7.4 Accessibility and Lighting

In its FIP, the licensee stated that the potential impairments to required access are: 1) doors and gates, and 2) site debris blocking personnel or equipment access. The coping strategy to maintain site accessibility through doors and gates is applicable to all phases of the FLEX coping strategies, and is immediately required as part of the immediate activities required during Phase 1. Doors and gates serve a variety of barrier functions on the site. One primary function is security and is discussed below. However, other barrier functions include fire, flood, radiation, ventilation, tornado, and high energy line break. As barriers, these doors and gates are typically administratively controlled to maintain their function as barriers during normal operations.

The licensee noted that following a BDBEE and subsequent ELAP event, FLEX coping strategies require the routing of hoses and cables to be run through various barriers in order to connect BDB equipment to station fluid and electric systems or require the ability to provide ventilation. For this reason, certain barriers (gates and doors) will be opened and remain open. This deviation of normal administrative controls is acknowledged and is acceptable during the implementation of FLEX coping strategies. The ability to open doors for ingress and egress, ventilation, or temporary cables/hoses routing is necessary to implement the FLEX coping strategies.

In its FIP, the licensee described that hands free battery powered portable lights are available in the control room (CR) for performing manual actions and traversing areas of low lighting. Additional battery powered light stands are staged in the PAB, CSR and CR to support operator actions.

3.7.5 Access to Protected and Vital Areas

During the audit process, the licensee provided information describing that access to protected areas will not be hindered. The licensee has contingencies in place to provide access to areas required for the ELAP response if the normal access control systems are without power. Security and operations personnel have keys and the training necessary to open doors and gates during an ELAP event to allow access to implement the Point Beach FLEX strategies. Redundant keys are also available. In its FIP, the licensee states that security doors and gates that rely on electric power to operate opening and/or locking mechanisms will be opened using keys that are provided to operations personnel. The security force will initiate an access contingency upon loss of power as part of the Security Plan. Access to the owner controlled area, site protected area, and areas within the plant structures will be controlled by security in accordance with the security plan. During the audit process, the licensee indicated that FSG procedures will list the doors needed for access and that the shift manager has a key to vital areas under his control, as backup to the normal keys stored in the control room.

3.7.6 Fueling of FLEX Equipment

In the Point Beach UFSAR, Section 8.8.3 states that there are two underground fuel oil storage tanks (FOSTs) each with a capacity of approximately 35,000 gallons. Furthermore, the UFSAR and the FIP indicate that the FOSTs are safety-related components located in the DG building on the 28 ft. elevation and meet Class I seismic criteria. In the FIP, Section 3.7.2.6 states that Technical Specification requirements ensure greater than 64,000 gallons of fuel oil is maintained in these two underground FOSTs and ensures that fuel oil quality in these tanks is provided by routine sampling and testing. By letter dated December 16, 2015, the licensee indicated in its "Order EA-12-049 Compliance Summary" that maintenance and testing will be conducted through the use of the Point Beach preventative maintenance program such that equipment reliability is maintained. During its audit, the staff noted in a sample set of FLEX preventative maintenance tasks that fluid analyses for portable FLEX equipment was included. Based on the design and location of these FOSTs and its safety-related classification, the staff concludes that the tanks are robust and the fuel oil contents should be available to support the licensee's FLEX strategies during an ELAP event. Furthermore, the NRC staff concludes that fuel oil quality is maintained in the FOSTs and portable FLEX equipment to ensure reliable equipment operation.

In the FIP, Section 3.7.2.6 states that the licensee's FLEX strategy includes a very limited number of small support engine powered equipment (chain saws, chop saws and small electrical generator units). This equipment is fueled and re-fueled using small portable containers of fuel located in the FSB or in designated FLEX storage locations in the plant (e.g., PAB). Based on the storage location of these fuel canisters, the staff concludes that the fuel contents are protected and should be available to power the small support engine-powered FLEX equipment during an ELAP event.

In the FIP, Section 3.7.2.6 states that with a conservative fuel oil consumption rate of 150 GPH and the ability to only draw approximately 2/3 of the FOSTs contents (42,000 gallons), this results in at least an 11 day supply of fuel oil. During its audit, it was noted that the fuel oil consumption rate was based on all FLEX equipment (N and N+1) continuous operation at full load. The staff notes that this consumption rate is conservative because it is not expected that the N set of equipment will operate at continuous full load for the duration of the ELAP event and the spare set (N+1) will not be operating simultaneously to support the FLEX strategies. In addition, during its audit, the licensee indicated that its existing NextERA Energy fuel oil contracts could be used as its long-term plan to replenish on-site fuel oil. Based on the conservative fuel oil consumption rate and the available on-site fuel oil from protected sources, the staff concludes that the licensee should have sufficient fuel oil on site to support its FLEX strategies. In addition, the staff concludes that the licensee should have sufficient time to obtain fuel oil from off-site for continued use of its Phase 2 and Phase 3 diesel-powered FLEX equipment during an ELAP event.

The FIP explained that refueling operation will be accomplished with a 500 gallon refueling trailer towed by a Ford F-350 or equivalent truck. The licensee indicated that the deployment vehicle and refueling trailer is stored in the FSB to ensure that it is protected and available during an ELAP event. Licensee procedure, FSG-5.5, "FLEX Equipment Refueling," Revision 0, specifically identifies the Phase 2 portable diesel powered FLEX equipment, the deployed location, the fuel consumption rate, fuel tank size, last and next refuel time in a tabular format. The staff notes that this table provides a quick reference to operators as to the amount of time a piece of FLEX equipment can be expected to operate per tank of fuel. In addition, the refueling scheduling tool provides the licensee the ability to track refueling operations and refueling needs of its diesel powered FLEX equipment to ensure equipment does not run out of fuel oil. Based on the available FLEX refueling equipment and the guidance provided in these procedures, the staff concludes that the diesel-powered FLEX equipment can be refueled in a timely manner to ensure uninterrupted operation to support the licensee's FLEX strategies.

3.7.7 Conclusions

Based on this evaluation, the NRC staff concludes that the licensee has developed guidance that, if implemented appropriately, should allow deploying the FLEX equipment following a BDBEE consistent with NEI 12-06, as endorsed by JLD-ISG-2012-01 and should adequately address the requirements of the order.

3.8 Considerations in Using Offsite Resources

3.8.1 Point Beach SAFER Plan

The industry has collectively established the needed off-site capabilities to support FLEX Phase 3 equipment needs via the SAFER Team. SAFER consists of the Pooled Equipment Inventory Company (PEICo) and AREVA Inc. and provides FLEX Phase 3 management and deployment plans through contractual agreements with every commercial nuclear operating company in the United States.

There are two NSRCs, located near Memphis, Tennessee and Phoenix, Arizona, established to support nuclear power plants in the event of a BDBEE. Each NSRC holds five sets of equipment, four of which will be able to be fully deployed to the plant when requested. The fifth set allows removal of equipment from availability to conduct maintenance cycles. In addition, the plant's FLEX equipment hose and cable end fittings are standardized with the equipment supplied from the NSRC.

By letter dated September 26, 2014 (ADAMS Accession No. ML14265A107), the NRC staff issued its assessment of the NSRCs established in response to Order EA-12-049. In its assessment, the staff concluded that SAFER has procured equipment, implemented appropriate processes to maintain the equipment, and developed plans to deliver the equipment needed to support site responses to BDBEEs, consistent with NEI 12-06 guidance; therefore, the staff concluded in its assessment that licensees can reference the SAFER program and implement their SAFER response plans to meet the Phase 3 requirements of Order EA-12-049. The NRC staff noted that the licensee's SAFER Response Plan contains (1) SAFER control center procedures, (2) NSRC procedures, (3) logistics and transportation procedures, (4) staging area procedures, which include travel routes between staging areas to the site, (5) guidance for site interface procedure development, and (6) a listing of site-specific equipment (generic and non-generic) to be deployed for FLEX Phase 3.

3.8.2 Staging Areas

In general, up to four staging areas for NSRC supplied Phase 3 equipment are identified in the SAFER Plans for each reactor site. These are a Primary (Area C) and an Alternate (Area D, if needed) which are offsite areas (within about 25 miles of the plant) for receipt of ground transported or airlifted equipment from the SAFER centers in Phoenix, Arizona or Memphis, Tennessee. From Staging Areas C and/or D, a near- or on-site Staging Area B is established for interim staging of equipment prior to it being transported to the final location for implementation in Phase 3 at Staging Area A. For Point Beach, Alternate Staging Area D is not applicable. Staging Area C is the Austin Straubel International Airport, "Oneida Lot," 2077 Airport Drive, Green Bay, WI 54313. Staging Area B is either of two large parking lots immediately north of the site on Lakeshore Road. Staging Area A is outside the station turbine or PAB, as appropriate.

Use of helicopters to transport equipment from Staging Area "C" to Staging Area "B" is recognized as a potential need and is provided for within the Point Beach SAFER Plan.

3.8.3 Conclusions

Based on this evaluation, the NRC staff concludes that the licensee has developed guidance that, if implemented appropriately, should allow utilization of offsite resources following a BDBEE consistent with NEI 12-06, as endorsed by JLD-ISG-2012-01, and should adequately address the requirements of the order.

3.9 Habitability and Operations

3.9.1 Equipment Operating Conditions

3.9.1.1 Loss of Ventilation and Cooling

Mechanical Equipment

In the FIP, Section 3.9 states following a BDBEE and subsequent ELAP event, ventilation providing cooling to occupied areas and areas containing FLEX equipment will be lost; thus, the primary concern is the heat buildup from the loss of forced ventilation in areas that continue to have heat loads. FIP Section 3.9.1 states that per UFSAR Section A.1.2 equipment operability is based on calculated maximum room temperature less than or equal to 120°F. The licensee used calculations 2005-0054, "Control Building GOTHIC Temperature Calculation," Revision 6, and 2013-0020, "PAB Scenarios for Fukushima Coping," Revision 0, to evaluate the temperature response during an ELAP event.

Calculation 2013-0020, Revision 0, "PAB Scenarios for Fukushima Coping", is a GOTHIC model of the loss of all powered ventilation in the PAB following an ELAP. Three scenarios were modeled:

1) Full core offload in the SFP, in which the pool starts boiling at 10 hours.;
2) All heat generation is lost and ambient temperature is -15°F; and
3) SFP begins boiling at 34 hours post ELAP representing load predicted for three months following a refueling outage.

Scenarios 1 and 3 assume slected doors are opened within 2 hours following the onset of an ELAP. The calculation looked at the PAB general area (46' elevation), the volume above the SFP, and the temperatures in several electrical rooms and battery rooms. The calculation determined that scenario 1 provides acceptable temperatures in the rooms of concern and envelops the results of scenario 3. Scenarios 1 and 3 assume a constant ambient temperature of 105°F for a little over 2 days (100,000 seconds).

Calculation 2005-0054, "Control Building GOTHIC Temperature Calculation", Revision 6, predicts the room temperatures in various rooms in the control building under design-basis accident conditions with the loss of offsite power, station blackout, and Appendix R with loss of ventilation. The calculation assumes a maximum summer ambient temperature of 100°F with a 16.4°F daily range and -15°F minimum winter ambient temperature. The calculation was performed for 24 hours. For temperaures after 24 hours, the licensee determined the temperatures using a linear extrapolation from the final few hours of the calculation.

During its audit, the NRC staff noted that Calculations 2005-0054 assessed the loss of ventilation to the AFW pump area and determined that by opening the doors within 2 hours after the loss of ventilation, all the rooms in this area would remain below the maximum allowable temperature for greater than 24 hours without any supplemental portable ventilation. In addition, the licensee indicated in its FIP that procedural guidance is provided to operators to open doors for the TDAFW pump room within 2 hours into the event, which is consistent with its calculation. The staff noted that FSG-5.6, "FLEX Miscellaneous Equipment and Monitoring," Revision 0 , provides guidance for opening up doors in the PAB to establish ventilation and to provide area monitoring at several locations in the plant, including the AFW pump room, for temperature, CO2 and radiation. Based on the expected temperature response in the AFW pump area, the opening of doors within 2 hours, and the procedural guidance for area monitoring, the NRC staff concludes that adequate ventilation should be provided to the mechanical equipment in the AFW pump area and the TDAFW pump should be available to support an ELAP event.

In addition, FIP Section 3.5.5 states that based on American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) data from the last 50 years, the licensee used 105.5°F for extreme high environmental conditions. Furthermore, the licensee explained that its FLEX equipment exposed to the environment are designed for this upper temperature limit. Specifically, per the equipment specifications, the FLEX PDSG, PDG and PDLP have a maximum temperature limit of 120°F, 122°F, and 118°F, respectively. Thus, the NRC staff concludes that the major portable FLEX equipment is designed to operate in extreme high temperatures and it is expected that this equipment will function during an ELAP event.

Electrical Equipment

As stated above, following a BDBEE and subsequent ELAP event, plant HVAC in occupied areas and areas containing permanent plant and FLEX mitigation strategy equipment will be lost. Therefore, the key areas that the licensee identified for all phases of execution of the FLEX strategy activities are control rooms, control building station battery rooms (D05, D06, D305) and inverter rooms ((D01, D02, D09), cable spreading rooms, PAB battery (D105 and D106) rooms (D225 and D228) and PAB battery charger and inverter rooms (226 and 227), PAB 1(2) B42 motor control center (MCC) area, TDAFW pump rooms, and containment. The licensee evaluated these areas to determine the temperature profiles following an ELAP/LUHS event.

The NRC staff reviewed calculations 2005-0054, "Control Building Gothic Temperature Calculation," Revision 6, 2013-0020, "PAB Scenarios for Fukushima Coping," Revision 0, and "HVAC Summary during Extended Loss of AC Power," Revision 1, to verify that equipment will not be adversely affected by increases in temperature as a result of loss of HVAC. The FLEX Procedures FSG-04 and FSG-05 provide guidance for monitoring room temperatures, opening doors and establishing ventilation after a loss of ventilation and cooling due to an ELAP.

Control Room

In calculation 2005-0054, the licensee determined that the expected room temperature in the control room will reach 120°F in 2.3 hours into an ELAP event with doors closed. The licensee stated that no immediate action is required. Opening doors between the control room and TB will reduce temperature rise and peak. Calculation 2005-0054 showed that opening doors between the CR and Turbine Building in 2 hours would result in a maximum temperature of 113.7°F. Portable fans can be used to cool the control room in accordance with FSG 5 and FSG 5.6. The licensee's evaluation showed that the control room temperature will be maintained at or below 120°F for the duration of the ELAP event. The licensee would also monitor control room temperature to determine if forced ventilation is needed. Procedure FSG 5.6, "FLEX Miscellaneous Equipment and Monitoring," Revision 0, provides guidance to the plant operators on monitoring control room. Based on temperatures remaining at or below 120°F (the temperature limit, as identified in NUMARC-87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," Revision 1, for electronic equipment to be able to survive indefinitely), the NRC staff concludes that the equipment in the control room will not be adversely impacted due to a loss of ventilation as a result of an ELAP event.

Control Building Station Battery (D05, D06, D305) Rooms

In calculation 2005-0054, the licensee determined that the expected temperatures in the Class 1E station battery room (D305) should reach 120°F in 3.6 hours (D05 in 5.0 hours and D06 in 6.6 hours) with the doors closed. The licensee's strategy includes opening doors between the Class 1E station battery rooms, control building, and TB to reduce temperature. The licensee will also monitor battery room temperature to determine the need for temporary forced ventilation to maintain temperature below 120°F. In calculation 2005-0054, the licensee identified 120 °F as the battery room (D05, D06 and D305) design acceptance limit. The Point Beach Class 1E station batteries D05, D06, and D305 were manufactured by Exide Technologies. In calculation 2005-0054, the licensee noted a letter from Exide Technologies that stated that the Point Beach batteries will work properly up to 160°F with shortened battery life; however, periodic monitoring of electrolyte level may be necessary to protect the battery since the battery may gas more at higher temperatures. Licensee procedure FSG-4 provides guidance on monitoring battery room temperatures using installed room or pilot cell thermometers and establishing battery room ventilation, if needed. Based on the above, the NRC staff concludes that the batteries in the Class 1E Station Battery rooms will not be adversely impacted due to a loss of ventilation as a result of an ELAP event.

D07, D08, D09 Battery Chargers Located in the Vital Switchgear Room (VSGR) Area

In its HVAC summary, the licensee stated that GOTHIC Calculation 2005-0054 provides an analysis of the VSGR under the Appendix R scenario because heat loading under the Appendix R scenario is more conservative than an ELAP event. Section 9.1.4 of the calculation (2005-0054) indicated that under higher heat load condition during Appendix R scenario, temperature in VSGR reaches 104°F in 19 hours. In the HVAC summary, Revision 1 dated August 6, 2015, the licensee stated that 104°F is well below the maximum allowed temperature limit of 120°F applicable to the battery chargers. The licensee will monitor VSGR temperature to determine need for opening doors to ensure temperatures stay below 120°F for the battery chargers. Since the temperature in VSGR is expected to remain below 120°F, (the temperature limit, as identified in NUMARC-87-00, Revision 1, for electronic equipment to be able to survive indefinitely), the NRC staff concludes that the D07, D08, and D09 Inverters will not be adversely impacted due to a loss of ventilation as a result of an ELAP event.

Inverters Located in the Cable Spreading Room

In Calculation 2005-0054, the licensee determined that the expected temperature in the Cable Spreading Room will reach 94.16°F in 2 hours during an ELAP and 120°F in approximately 4.7 hours. In its HVAC summary evaluation, "HVAC Summary During an Extended Loss of AC Power," Revision 1, the licensee stated that the Point Beach mitigation strategies includes opening doors prior to 4 hours into the event and monitoring temperature to determine the need to deploy temporary forced ventilation to keep room temperature below 120°F. Licensee procedure FSG 5.6 provides guidance on monitoring the cable spreading room temperature. Based on the licensee's strategy to maintain the cable spreading room temperature at or below 120°F (the temperature limit, as identified in NUMARC-87-00 Revision 1, for electronic equipment to be able to survive indefinitely), the NRC staff concludes that the electrical equipment in the cable spreading room will not be adversely impacted by the loss of ventilation as a result of an ELAP event.

PAB Battery (D105 and D106) Rooms (225 and 228)

As stated in the licensee HVAC summary, revision 1, calculation 2013-0020 determined that the maximum (peak) temperature in the PAB battery rooms (225 and 228) is expected to reach 107.0°F at 16 hours and 108°F at 24 hours. The room temperature drops to 111.5°F in 5 hours and then expected to remain below 114°F after 24 hours. The PAB batteries (D105 and D106) were manufactured by C&D Technologies. The qualification testing performed by C&D Technologies demonstrated the ability to perform under elevated operating temperature environments. The testing results indicate that the battery cells will perform as required in excess of 200 days under an estimated 122°F; however, periodic monitoring of electrolyte level may be necessary to protect the battery since the battery may gas more at higher temperatures. The licensee's mitigation strategy includes monitoring room temperature, opening doors and providing forced ventilation using a portable fan. Procedure FSG 5.6 provides guidance to the operator to monitor temperature of PAB Battery Rooms 225 and 228 and establish ventilation such as opening doors or forced ventilation, if necessary.. Based on the above, the NRC staff concludes that the equipment in the PAB battery rooms (225 and 228) will not be adversely affected due to a loss of ventilation during an ELAP.

PAB Battery Charger and Inverter Rooms 226 and 227

As stated in the licensee's HVAC summary, revision 1, calculation 2013-0020 determined that the maximum peak temperature in the PAB battery charger and inverter rooms (226 and 227) is expected to reach 122°F at 24 hours. As discussed in calculation N-94-064, the licensee reviewed the limiting component in the Inverter rooms 226 and 227 and determined that the battery chargers D-107, D108, D109, and yellow and white Inverters are the limiting components and are capable of operating in an ambient environment of 122°F. Procedure FSG 5.6 provides guidance to the operator to monitor temperature of PAB Rooms 226 and 227 and maintain room temperature below maximum temperature limit of 120°F by establishing ventilation such as door openings or portable forced ventilation if necessary. Since the battery chargers and Inverters are capable of operating at an ambient temperature of 122°F. Since the expected peak temperature (117.8°F) in the inverter rooms remaining below 120°F (the temperature limit, as identified in NUMARC-87-00 Revision 1, for most of equipment to be able to survive indefinitely), the NRC staff concludes that the electrical equipment in the battery charger and inverter rooms 226 and 227 will not be adversely impacted by the loss of ventilation as a result of an ELAP event.

PAB 1(2) B42 MCC Area

In Calculation 2013-0020, and in the licensee's evaluation, "HVAC Summary During an Extended Loss of AC Power," Revision 1, the licensee determined that the maximum expected temperature in the PAB 1(2) B42 MCC area would be 104°F in 2 hours and 106°F in 9 hours respectively when ventilation pathway doors are opened. The temperature is expected to remain constant at 105°F thereafter.

Based on the temperature remaining at or below 120°F (the temperature limit, as identified in NUMARC-87-00, Revision 1, for electrical equipment to be able to survive indefinitely), the NRC staff concludes that the electrical equipment in the PAB 1(2) B42 MCC area will not be adversely impacted by a loss of ventilation as a result of an ELAP event.

Unit 1 and Unit 2 TDAFW Pump Rooms

In Calculation 2005-0054, and in "HVAC Summary During an Extended Loss of AC Power," Revision 1, the licensee determined that the expected temperature in the Unit 1 and Unit 2 TDAFW pump rooms would reach120°F after 2 hours during an ELAP with both TDAFW Pump room doors closed. The licensee stated that the Point Beach mitigating strategy includes opening both TDAFW Pump room doors and the Unit 1 to Unit 2 TB doors within 2 hours, and stage and start portable fans. Licensee procedure FSG 5.6 provides guidance on monitoring the TDAFW pump room temperature to ensure temperature remains at or below 120°F. Based on TDAFW pump room temperatures remaining at or below 120°F (the temperature limit, as identified in NUMARC-87-00, Revision 1, for electronic equipment to be able to survive indefinitely), the NRC staff concludes that the electrical and electronic equipment in the TDAFW pump rooms will not be adversely impacted by a loss of ventilation as a result of an ELAP event.

Containment

In its FIP, the licensee stated that based on the use of low leakage RCP seals, the containment pressure will reach a peak value of 17.2 psia and a temperature of 148°F approximately 2 days after the ELAP event. These values are significantly less than the design limits of 75 psia and 286°F. The licensee's evaluations have concluded that containment temperature and pressure will remain below containment design limits and that key parameter instruments subject to the containment environment will remain functional. Actions to reduce containment temperature and pressure and to ensure continued functionality of the key parameters should not be required immediately. If temperature or pressure rise does occur that could challenge containment or required instrumentation, plant operators could vent or cool containment utilizing guidance in FSG-12, "Alternate Containment Cooling," Revision 0. The licensee's guidance in FSG-12 provides several different methods for providing containment cooling to ensure containment temperature and pressure remain below containment design limits and key parameter instruments subject to the containment environment remain functional.

During Phase 3, any necessary actions to reduce containment temperature and pressure utilize existing plant systems powered by offsite equipment. The two portable 4160 Vac CTGs and a distribution panel that will be supplied by NSRC for each unit can be used to supply power to the Class 1E 4160 Vac bus in each unit, providing another option for powering various station pumps or fans.

As described in FSG-12, in the event that it becomes necessary to cool or vent containment, the 4160 Vac CTGs could also be used to power the containment cooling fans to accomplish this task. In the FIP, the licensee stated that the primary strategy for Phase 3 is to restore power to the containment cooling fans and cooling water flow to the containment cooling fans utilizing the NSRC supplied 4160 Vac CTGs. An NSRC will also provide portable diesel driven low pressure pumps that could be used to provide cooling loads to various water systems, if needed. Based on its review, the NRC staff concludes that the electrical equipment within containment will not be adversely affected by increases in temperature as a result of loss of ventilation.

3.9.1.2 Loss of Heating

Scenario 2 of calculation 2013-0020, Revision 0, addresses the loss of heating during cold weather. The calclulation assumes a continuous ambient temperature of -15°F for 12.5 hours. The temperature at 24 hours was determined using a linear extrapolation from the final few hours of the calculation (time interval was arbitrarily chosen as the last 100 data points). With the exception of the containment facades and the No.3 Pipeway and Valve Gallery, most areas remain above freezing. It will take more than 12 hours for this area to drop below freezing. This will provide sufficient time to deploy heaters.

The FIP explained that precautions are established for FLEX pump suction and discharge hoses located outside during extreme cold conditions. Specifically, FSG-5.4, "FLEX Pump Operations," Revision 0, provides procedural guidance and caution to operators to delay charging hoses with water until it is needed since freezing may occur without water flow and that hoses should be drained when not in use to prevent freezing. In addition, the licensee explained that the plant heat tracing system is intact and the FLEX DG connected to safeguards buses 1B-03 and 2B-03 can be used to repower portions of the heat trace system. Based on the procedural guidance to prevent freezing in FLEX pump suction and discharge hoses and the ability to repower the heat trace systems with the FLEX DG, the NRC staff concludes that the loss of heating appears to be adequately addressed during an ELAP event.

PAB Battery Rooms (D105 and D106) and Control Building Battery Rooms (D05, D06 and D305)

With regard to loss of heating in the Point Beach safety-related battery rooms as a result of an ELAP, battery room temperatures are expected to rise due to discharge and nearby passive heat sinks with loss of ventilation. Calculations 2005-0054 and 2013-0020 assumed the initial battery room temperature of 85°F at the start of an ELAP event. Therefore, reaching the minimum battery room temperature limit (69°F) assumed in the calculation 2014-0013 is not expected when battery is discharging during Phase 1 of an ELAP. During battery discharge, the battery will be producing heat that will keep electrolyte temperature above the room temperature. Procedure FSG-5 provides guidance on staging heating and ventilation equipment, and Procedure FSG 5.6 monitors the room temperature and takes actions such as opening doors, cabinets and installs temporary heating and ventilation equipment, as necessary to ensure continued functionality of the batteries for entire ELAP duration. During the audit review, the licensee stated that a procedure change notice 2148970has been initiated to revise Procedure 5.6 to identify the minimum allowable temperatures for the battery rooms. Based on the above, the NRC staff concludes that the Point Beach safety-related batteries should perform their required functions at the expected temperatures as a result of loss of heating during an ELAP event.

3.9.1.3 Hydrogen Gas Control in Vital Battery Rooms

An additional ventilation concern that is applicable during Phases 2 and 3 is the potential buildup of hydrogen in the vital battery rooms D05, D06, D105, D106, and D305, as a result of loss of ventilation during an ELAP event. Off-gassing of hydrogen from batteries is only a concern when the batteries are charging. In Point Beach calculation N-93-041, "Hydrogen Buildup in the Battery Rooms," Revision 3, the licensee determined that the most limiting time is 7.5 hours at 120°F for hydrogen concentration to reach 2 percent. In order to prevent a buildup of hydrogen in the battery rooms, the licensee's procedure FSG-4 directs plant operators to energize the battery room exhaust fans. These fans will be powered from the 480 Vac bus connected to the FLEX 480 Vac FLEX DG. The battery room exhaust fans will exhaust battery room air through the normal exhaust flow path to prevent hydrogen accumulation. If the battery room ventilation is not available, FSG-4 provides guidelines to establish temporary ventilation to address this condition.

Based on its review, the NRC staff concludes that the licensee's evaluation demonstrated that hydrogen accumulation in the 125 Vdc battery rooms should not reach the combustibility limit for hydrogen (4 percent) during an ELAP as a result of a BDBEE since the licensee plans to repower the battery room exhaust fans when the battery chargers are repowered during Phases 2 and 3 or use portable ventilation.

3.9.2 Personnel Habitability

By letter dated April 7, 2016 (ADAMS Accession No. ML16098A306), the licensee informed the NRC of their intention to use NEI 12-06, Revision 2. Section 3.2.1.8 of the NEI guidance states that the effects of a loss of heating, ventilation and air condition (HVAC) in an ELAP event can be addressed consistent with NUMARC 87-00, Revision 1. Section 2.7 of NUMARC 87-00 indicates that a dry bulb temperature of 110°F is tolerable for light work for a four hour period while dressed in conventional clothing assuming the relative humidity is approximately 30 percent.

3.9.2.1 Main Control Room

The licensee preformed calculation 2005-0054, "Control Building GOTHIC Temperature Calculation," Revision 6, to predict post-accident transient temperature profile in various rooms in the control building. The "accident" scenarios included a station blackout (SBO). Section 9.1.5 of the calculation shows that the control room temperature will exceed 113°F at 2-hours. The table in Section 9.1.5 indicates that the maximium allowable temperature for the control room is 120°F. This is contrary to the guidance in NEI 12-06, Revision 2 which adopts the NUMARC 87-00 control room maximum temperature of 110°F. The calculation does not indicate the control room temperature during an ELAP greater than 2 hours. As part of the audit process, the licensee was requested to provide clarification. The calculation referenced was considered to envelope the conditions for the control room. A maximum outdoor ambient temperature is assumed to be at 100°F with a diurnal range of 16.4°F. The electrical loads for a SBO event are higher than for an ELAP event. The ELAP electrical loads are reduced to maximize battery life. In addition, staffing in the control room will be reduced during an ELAP as operators are dispatched to carry out field actions. Furthermore, the control room is continuously staffed. Operators are expected to take actions to maintain habitability. FSG-04 and FSG-05 along with FSG-5.6 provide guidance on which doors to open. After review, the NRC staff concludes that the long term habitability in the control room should not be adversely impacted by the loss of ventilation as a result of an ELAP event.

3.9.2.2 Spent Fuel Pool Area

In the FIP, Section 3.3.4.1.1 states that ventilation to the SFP area prevents excessive steam accumulation in the PAB and is accomplished by blocking open personnel and equipment doors. The licensee performed a calculation of the temperatures in the PAB general area and above the SFP in calculation, 2013-0020, "PAB Scenarios for Fukushima Coping," and determined that with the opening of these doors, the SFP area temperature will not exceed 108°F.

As discussed in SE Section 3.3, based on typical SFP heat loading with a full core offload and initial SFP temperature of 100°F, the projected time for the SFP to reach 200°F is approximately 11 hours. The licensee's FIP and sequence of events indicate that doors on the 66 ft. elevation of the PAB and the truck bay door will be opened to establish ventilation flow path in anticipation of SFP boiling within 9 hours from event initiation to ensure the SFP area remains habitable for personnel entry. In addition, within 9 hours from event initiation, the licensee will install spray nozzles and route hoses from the SFP refueling deck to the 8 ft. elevation of the PAB to ensure the SFP area remains habitable. Procedure FSG-5.6, "FLEX Miscellaneous Equipment and Monitoring," provides a caution to operators that there is excess of 10 hours from the initiating event to establish a vent pathway in PAB for SFP steam and those doors in the higher elevation should be opened first. In addition, FSG-5.6 explicitly identifies the specific plant doors that can be opened to establish ventilation in the Primary Auxiliary Building.

Based on time to boil in the SFP, and the cautions and procedural guidance in FSG-5.6, the staff concludes that operators should be able to safely enter the area of the SFP to establish a vent path and begin deploying FLEX equipment.

3.9.2.3 Other Plant Areas

The TDAFWP room evaluated in calculation 2005-0054, Section 9.1.5 determined that if the room doors are opened at 2 hours, the temperature will remain below 120°F after 24 hours. FSG-4, "ELAP DC Bus Load Shed / Management," Attachment G provides guidance for door opening. Document ECA-0.0, "Loss of All AC Power," provides guidance for monitoring the AFW pump room temperature and directs operators to abnormal operating procedure (AOP)-30, "Temporary Ventilation for Vital Areas," if the room temperature exceeds temperature limits.

The cable spreading room was evaluated in calculation 2005-0054, Revision 6. The calculation determined that the room will heatup to 94°F 2 hours following an ELAP. Conditions will be monitored in accordance with FSG-5. Doors will opened as required to provide ventilation. FSG-4, Attachment H provides guidance for establishing ventilation to the inverter rooms and battery rooms. Portable fans are available to provide additional ventilation.

3.9.3 Conclusions

Based on the evaluation above, the NRC staff concludes that the licensee has developed guidance that, if implemented appropriately, should maintain or restore equipment and personnel habitability conditions following a BDBEE consistent with NEI 12-06, as endorsed by JLD-ISG-2012-01, and should adequately address the requirements of the order.

3.10 Water Sources

3.10.1 Steam Generator Make-Up

Phase 1

In the FIP, Section 3.2.2.1.1 states that the CSTs provide a water source at the initial onset of the event for the core cooling and heat removal strategy. The FIP explains that anchorage modifications were made to the CSTs as part of EC 279034, "NRC Order Fukushima FLEX CSTs Seismically Upgrade and Missile Protect Bottom 6 feet." During its audit, the staff noted that the CSTs are located within the TB and are above the flood elevation. Furthermore, it was noted that the upgrades to the CSTs installed additional anchors at the base of the tanks and tornado missile barriers in the TB to protect the CST to 6 feet above the TDAFW pump suction connection. With these modifications, the CST usable volume is at least 14,100 gallons per unit for makeup to the SGs for both units and ensures that 1 hour 53 minutes of decay heat removal time is available to allow switchover to the alternate suction source. The licensee's sequence of events indicate that operators will be directed 15 minutes after event initiation to begin aligning an alternate suction source to the TDAFW pumps, and by 1 hour and 45 minutes after event initiation, service water flow to the TDAFW pumps via the DDFP will be established.

Based on the location and modifications to the CST, the licensee should have an adequate source of water available during Phase 1 core cooling. In addition, the licensee's strategy should provide sufficient time for operators to deploy and stage Phase 2 FLEX equipment.

Phase 2

During Phase 2, once the volume in the CSTs have been exhausted, the DDFP will take suction from the SW pump bay in CWPH and discharge directly to the suction of the TDAFW pump. If the TDAFW pump is no longer available, the FLEX PDSG pump can take suction from the CWPH SW pump bay, CWPH forebay or direct draft from Lake Michigan.

In the UFSAR, Section A.5.2 indicates that the CWPH is a seismic Class I structure and UFSAR Section 1.3.1 states that the seismic Class I portions of the CWPH is designed to withstand the effects of a tornado. Therefore, the NRC staff concludes that the CWPH service water pump bay is robust with respect to applicable external hazards and should be available to support the licensee's core cooling FLEX strategies for decay heat removal.

The licensee explained that the CWPH forebay design provides four connection paths to Lake Michigan (two intake pipes and two discharge flumes) and any one of the paths is capable of supplying a quantity of water well in excess of the amount required to support its FLEX strategies. The staff noted that these four connection points to Lake Michigan are not seismically robust; however, the licensee explained that there is 440,826 gallons contained in the forebay pump bays, should the connection to Lake Michigan not be available, and that this volume provides greater than 24 hours of decay heat makeup for both units. Furthermore, the NRC staff noted that although the UHS is relied upon to provide makeup to the SFP, after reaching the boiling point, it would take an additional 71 hours for the SFP to boil down to 6 inches above the fuel. Thus, if the connection between the forebay pump bays and Lake Michigan is not available during an ELAP event, the staff concludes that the volume of water contained in the forebay pump bays should be sufficient to solely support the core cooling strategies until the connection between the pump bay forebay and Lake Michigan is reestablished.

Therefore, the licensee should have an adequate source of water available during Phase 2 core cooling. In addition, the licensee's strategy should provide sufficient time for off-site resources from the NSRC to arrive and begin deploying and staging Phase 3 FLEX equipment and reestablish the connection between the forebay and Lake Michigan, if necessary.

3.10.2 Reactor Coolant System Make-Up

Phases 1, 2 and 3

The FIP indicates that RCS makeup is not required for Phase 1 since the RCP seals were upgraded and will allow negligible RCS inventory losses such that RCS makeup is no longer required to achieve a stable steady state in Phase 1. The FIP indicates that the RWSTs (primary) and BASTs (alternate) are suction sources of borated water for the PDCP to support the Phase 2 and 3.

In the UFSAR, Section A.5.2 indicates that the RWSTs are seismic Class I structures; however, the licensee explained in the FIP that the tank is not located in a Class I structure that would protect it from tornado wind loading and missiles. The licensee stated that the RWSTs are protected from the surrounding plant grade to the 26 ft. plant elevation and are also protected from the 26 ft. plant elevation up to the 46 ft. plant elevation on all sides by adjacent Class I concrete structures (containment building, PAB, SFP transfer canal, and pipeways 1, 2, 3 and 4). During the staff's audit, the licensee explained that approximately 54 percent of the RWSTs are protected, which equates to ~160,000 gallons of borated water. Based on the surrounding plant grade and robust Class I structures, the staff concludes that the lower potions of the RWSTs are protected from the effects of a tornado and this volume is sufficient to support the licensee's FLEX strategies for greater than 72 hours.

In the FIP, Section 3.2.2.5.5 states that the BASTs are located within the PAB, which is a seismic Class I structure and is designed to withstand the effects of a tornado (wind force, pressure differential, and missile impingement). The licensee explained that the BASTs were originally designed and installed as seismic Class I but were administratively down graded to Class II when their safety related function was changed and are considered as a backup source of borated water to support its FLEX strategies.

Based on the location and design of the RWSTs and BASTs, the staff concludes that the tanks are robust with respect to applicable external hazards as described in Section 3.5 of this SE and should be available to support the licensee's FLEX strategies during an ELAP event.

3.10.3 Spent Fuel Pool Make-Up

Phases 1, 2 and 3

As discussed in Section 3.3 of this SE, SFP boiling during non-outage situations is expected to conservatively begin 11 hours after the ELAP initiating event and will take an additional 71 hours to reach 6 inches above the fuel. The licensee will monitor SFP level using instrumentation installed as required by NRC Order EA-12-051 throughout Phase 1 and 2 and provide make up via the FLEX PDSG or spray via the FLEX PDLP with suction from the CWPH SW pump bay, CWPH forebay or Lake Michigan.

As previously discussed in Section 3.10.1 of this SE, the CWPH SW pump bay, CWPH Forebay or Lake Michigan is robust with respect to the applicable external hazards. Therefore, the staff concludes that the water volume available in the CWPH SW pump bay, CWPH Forebay or Lake Michigan should provide the licensee with sufficient time to deploy Phase 3 FLEX equipment to reestablish SW cooling flow to the SFP heat exchangers and should provide power to the SFP pumps.

3.10.4 Containment Cooling

Phases 1, 2 and 3

As discussed in Section 3.4 of this SE, a FLEX containment analysis based on the use of low leakage RCP seals determined that approximately 2 days after the ELAP initiating event, the containment will reach a pressure of 17.2 psia and a temperature of 148° F, which are significantly less than the design limits of 75 psia and 286° F. The licensee does not expect that the design containment pressure and temperature will be challenged but, if necessary, the PDLP with suction from CWPH SW pump bay, CWPH forebay or Lake Michigan can supply water to the CS system via an adapter that will replace the cover of a CS pump discharge check valve, 1(2)SI-862A/B.

As previously discussed in Section 3.10.1 of this SE, the CWPH SW pump bay, CWPH Forebay or Lake Michigan is robust with respect to the applicable external hazards. Therefore, the staff concludes that the water volume available in the CWPH SW pump bay, CWPH Forebay or Lake Michigan provides the licensee with sufficient time to deploy Phase 3 FLEX equipment to restore power to the containment cooling fans and cooling water flow to the containment fan coolers.

3.10.5 Conclusions

Based on the evaluation above, the NRC staff concludes that the licensee has developed guidance that, if implemented appropriately, should maintain satisfactory water sources following a BDBEE consistent with NEI 12-06, as endorsed by JLD-ISG-2012-01, and should adequately address the requirements of the order.

3.11 Shutdown and Refueling Analyses

Order EA-12-049 requires that licensees must be capable of implementing the mitigation strategies in all modes. In general, the discussion above focuses on an ELAP occurring during power operations. This is appropriate, as plants typically operate at power for 90 percent or more of the year. When the ELAP occurs with the plant at power, the mitigation strategy initially focuses on the use of the steam-driven TDAFW pump to provide the water initially needed for decay heat removal. If the plant has been shut down and all or most of the fuel has been removed from the RPV and placed in the SFP, there may be a shorter timeline to implement the makeup of water to the SFP. However, this is balanced by the fact that if immediate cooling is not required for the fuel in the reactor vessel, the operators can concentrate on providing makeup to the SFP. The licensee's analysis shows that following a full core offload to the SFP, about 11 hours are available to implement makeup before boil-off results in the water level in the SFP dropping far enough to uncover fuel assemblies, and the licensee has stated that they have the ability to implement makeup to the SFP within that time.

When a plant is in a shutdown mode in which steam is not available to operate the TDAFW pump and allow operators to release steam from the SGs (which typically occurs when the RCS has been cooled below about 300 °F), another strategy must be used for decay heat removal. The NRC-endorsed strategy is described in NEI 12-06. Section 3.2.3 provides guidance to licensees for reducing shutdown risk by incorporating FLEX equipment in the shutdown risk process and procedures. Considerations in the shutdown risk assessment process include maintaining necessary FLEX equipment readily available and potentially pre-deploying or pre-staging equipment to support maintaining or restoring key safety functions in the event of a loss of shutdown cooling. In its FIP, the licensee stated that it would follow this guidance. During the audit process, the NRC staff observed that the licensee had made progress in implementing this guidance.

Based on the licensee's incorporation of the use of FLEX equipment in the shutdown risk process and procedures, the NRC staff concludes that the licensee has developed guidance that if implemented appropriately should maintain or restore core cooling, SFP cooling, and containment following a BDBEE in shutdown and refueling modes consistent with NEI 12-06 guidance, as endorsed by JLD-ISG-2012-01, and should adequately address the requirements of the order.

3.12 Procedures and Training

3.12.1 Procedures

Regarding procedures, the licensee stated in the FIP that the inability to predict actual plant conditions that require the use of BDB equipment makes it impossible to provide specific procedural guidance. As such, the FSGs will provide guidance that can be employed for a variety of conditions. Clear criteria for entry into FSGs will ensure that FLEX strategies are used only as directed for BDBEE conditions, and are not used inappropriately in lieu of existing procedures. When BDB equipment is needed to supplement EOPs or AOPs strategies, the EOP or AOP will direct the entry into and exit from the appropriate FSG procedure.
FLEX strategy support guidelines have been developed in accordance with PWROG guidelines. The FSGs will provide available, preplanned FLEX strategies for accomplishing specific tasks in

the EOPs or AOPs. The FSGs will be used to supplement (not replace) the existing procedure structure that establishes command and control for the event. Procedural interfaces have been incorporated into 1(2)ECA-O.O, Loss of All AC Power, and SEP 3.0 Unit 1(2), Loss of All AC Power While on Shutdown Cooling, to the extent necessary to include appropriate reference to FSGs and provide command and control for the ELAP.

The licensee stated that validation has been accomplished via walk-throughs or drills of the guidelines and abides by the guidance provided by NEI.

3.12.2 Training

In its FIP, the licensee stated that initial training has been provided and periodic training will be provided to site emergency response leaders on beyond-design-basis emergency response strategies and implementing guidelines. In addition, personnel assigned to the direct execution of mitigation strategies for BDBEEs have received the necessary training to ensure familiarity with the associated tasks, instructions, and mitigating strategy time constraints. The training plan development was done in accordance the Systematic Approach to Training (SAT) process.

Based on the description provided above, the NRC staff concludes that, as described, the licensee's established procedural guidance meets the provisions of NEI 12-06, Section 11.4 (Procedure Guidance). Similarly, the NRC staff concludes that the training plan, including use of the SAT for the groups most directly impacted by the FLEX program, meets the provisions of NEI 12-06, Section 11.6 (Training).

3.13 Maintenance and Testing of FLEX Equipment

As a generic issue, NEI submitted a letter dated October 3, 2013 (ADAMS Accession No. ML13276A573), which included EPRI Technical Report 3002000623, "Nuclear Maintenance Applications Center: Preventive Maintenance Basis for FLEX Equipment." In a letter dated October 7, 2013 (ADAMS Accession No. ML13276A224), the NRC endorsed the use of the EPRI report and the EPRI database as providing a useful input for licensees to use in developing their maintenance and testing programs. Preventative maintenance templates for the major FLEX equipment have also been issued.

In its FIP, the licensee stated that equipment required to implement the FLEX strategies for Point Beach has been procured in accordance with NEI 12-06, Section 11.1 and 11.2, and initially tested or has its performance verified as identified in NEI 12-06, Section 11.5, and is available for use. Maintenance and testing will be conducted through the use of the Point Beach Preventative Maintenance program such that equipment reliability is maintained.

Based on the use of the endorsed program, which establishes and maintains a maintenance and testing program in accordance with NEI 12-06, Section 11.5, the NRC staff concludes that the licensee has adequately addressed equipment maintenance and testing activities associated with FLEX equipment.

3.14 Conclusions for Order EA-12-049

Based on the evaluations above, the NRC staff concludes that the licensee has developed guidance to maintain or restore core cooling, SFP cooling, and containment following a BDBEE which, if implemented appropriately, should adequately address the requirements of Order EA-12-049.

4.0 TECHNICAL EVALUATION OF ORDER EA-12-051

By letter dated February 22, 2013 (ADAMS Accession No. ML13053A399), the licensee submitted its OIP for Point Beach in response to Order EA-12-051. By email dated May 29, 2013 (ADAMS Accession No. ML13154A166), the NRC staff sent a request for additional information (RAI) to the licensee. The licensee provided a response to the RAI by letter dated July 3, 2013 (ADAMS Accession No. ML13186A012). By letter dated November 18, 2013 (ADAMS Accession No. ML13309A011), the NRC staff issued an Interim Staff Evaluation (ISE) and RAIs to the licensee.

By letters dated August 28, 2013 (ADAMS Accession No. ML13241A202), February 28, 2014 (ADAMS Accession No. ML14059A086), and August 28, 2014 (ADAMS Accession No. ML14241A268), the licensee submitted status reports for the Integrated Plan. The Integrated Plan describes the strategies and guidance to be implemented by the licensee for the installation of reliable spent fuel pool instrumentation (SFPI), which will function following a BDBEE, including modifications necessary to support this implementation, pursuant to Order EA-12-051. By letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), the licensee reported that full compliance with the requirements of Order EA-12-051 was achieved.

The licensee has installed a SFPI system (SFPIS) designed by Westinghouse. The NRC staff audited Westinghouse's SFPI system design specifications, calculations and analyses, test plans, and test reports in support of the NRC staff review of licensees' OIPs in response to Order EA-12-051. The NRC issued an audit report on August 18, 2014 (ADAMS Accession No. ML14211A346).

In support of drafting this SE, the NRC staff performed an onsite audit at Point Beach from June 8-12, 2015, to review the implementation of SFP level instrumentation related to Order EA-12-051. The scope of the audit included verification of (a) site's seismic and environmental conditions enveloped by the equipment qualifications, (b) equipment installation met the requirements and vendor's recommendations, and (c) program features met the requirements. By letter dated July 30, 2015 (ADAMS Accession No. ML15211A533), the licensee provided RAI responses to the staff's questions generated during the onsite audit. Refer to Section 2.2 above for the regulatory background for this section.

4.1 Levels of Required Monitoring

In its OIP, the licensee stated that Level 1 is the indicated level on either the primary or backup instrument channel of greater than or equal to 23 ft. above the top of the irradiated fuel assemblies seated in the storage racks, at plant elevation 60 ft. 9 in. The licensee also stated that this level is above the SFP cooling suction and return connections' siphon breaker at plant elevation 59 ft. 8 in.

In its letter dated July 3, 2013, the licensee stated, in part, that:

> The level at which reliable suction loss occurs due to uncovering the coolant inlet pipe or any weirs or vacuum breakers associated with suction loss is established based on nominal coolant inlet pipe elevation and siphon breaker termination. This level is plant elevation 59 feet 8 inches.
>
> The level at which the normal SFP cooling pumps lose required net positive suction head (NPSH), assuming saturated conditions in the pool, is below the elevation that defines Level 1. The centerline of the cooling pump suction is at plant elevation 59 feet 6 inches and the centerline of the SFP cooling pump impellers is at plant elevation 48 feet 2 inches. With the spent fuel pool at 212 degrees F, saturated conditions, the NPSH available (NPSHA) is approximately 11.5 feet. The NPSH required (NPSHR) for the pump is 5 feet at 212 degrees F. This results in a NPSHA/NPSHR value of approximately 2.3. Therefore, the NPSHA is greater than the NPSHR at saturated conditions and the siphon break will uncover prior to pump cavitation. Therefore, the Level 1 elevation is established at 59 feet 8 inches for both primary and backup instrumentation.

The NRC staff notes that for Point Beach, Level 1 at 59 ft. 8 in. is adequate for normal SFP cooling system operation; it is also sufficient for NPSH and represents the higher of the two points described in NEI 12-02 for this level.

In its OIP, the licensee stated that Level 2 is the indicated level on either the primary or backup instrument channel of greater than 10 ft. above the top of the irradiated fuel assembles seated in the storage racks, which is at plant elevation of 47 ft. 9 in.

In its letter dated July 3, 2013, the licensee provided a sketch depicting the elevations identified as Levels 1, 2 and 3 and the SFP level instrument measurement range. The NRC staff reviewed this sketch and notes that Level 2 is identified at an elevation of 49 ft. 0 in. The staff notes that Level 2 was revised from 47ft. 9 in., provided in the OIP, to 49ft. 0 in. The staff also notes that this elevation is more than 10 ft. above the top of the fuel racks and that the licensee designated Level 2 using the first of the two options described in NEI 12-02 for Level 2.

In its OIP, the licensee stated, in part, that:

> Indicated level on either the primary or backup instrument channel of greater than 2 feet 11 inches (plant elevation 40 feet 8 inches) above the top of the irradiated fuel assemblies seated in the storage racks. This monitoring level assures that there is adequate water level above the stored fuel seated in the rack. This monitoring level is where actions to implement makeup water addition should no longer be delayed.
>
> The top of the fuel assemblies is located at plant elevation 37 feet 9 inches. The top of the east west oriented wall opening that separates the northern and southern areas of the SFP is at plant elevation 40 feet 8 inches. Once the water level drops below this point, the single SFP has effectively been segregated into

> two separate pools. Consequently, plant elevation 40 feet 8 inches is the level at which actions to initiate water make-up should not be further delayed. This setting is in compliance with the Order. This is a conservative decision to treat plant elevation 40 feet 8 inches as the top of the fuel and necessary to ensure proper actions are taken in the event that one of the channels of SFP level instrumentation is lost or in the event that level is decreasing due to a breach in one of the pits.

In its letter dated July 3, 2013, the licensee stated, in part, that:

> For Level 3, with regard to the spent fuel pool design, there are no means, temporary or permanent, to further segregate the north/south pool areas.

In addition, in its letter dated July 3, 2013 (ADAMS Accession No. ML13186A012), the licensee provided a sketch depicting the elevations identified as Levels 1, 2 .and 3 and the SFP level instrument measurement range. The NRC staff reviewed this sketch and notes that Level 3 is identified at a plant elevation of 40 ft. 8 in., which is in alignment with the top of the east/west oriented wall opening which separates the northern and southern areas of the SFP. The NRC staff also notes that this elevation is above the highest point of any spent fuel storage rack seated in the SFP. This elevation ensures that level indication will be continuous and consistent for primary and backup instruments and will not be interrupted by pool segregation caused by the east/west wall.

The staff concludes that Level 1 is adequate for normal SFP cooling system operation; it is also appears to be sufficient for NPSH and represent the higher of the two points. Level 2 is approximately 10 ft. above the top of fuel rack and represents the range of water level where any necessary operation in the vicinity of the SFP can be completed without significant dose consequences. Level 3 is above the highest point of any fuel storage rack seated in the SFP. At this level, fuel remains covered.

Based on the discussion above, the NRC staff concludes that the licensee's proposed Levels 1, 2, and 3 appear to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2 Evaluation of Design Features

Order EA-12-051 required that the SFP level instrumentation shall include specific design features, including specifications on the instruments, arrangement, mounting, qualification, independence, power supplies, accuracy, testing, and display. Below is the staff's assessment of the design features of the SFP level instrumentation.

4.2.1 Design Features: Instruments

In its OIP, the licensee stated that the primary and backup instrument channels will consist of fixed components. The plan is for both channels to utilize Guided Wave Radar, which functions according to the principle of time domain reflectometry (TDR). A generated pulse of electromagnetic energy travels down the probe. Upon reaching the liquid surface, the pulse is reflected, and based upon reflection time, level is inferred. Primary instrument channel level sensing components will be located near the north wall of the SFP. Backup instrument channel level sensing components will be located near the south wall of the SFP approximately 78 ft. from the primary instrument channel.

The NRC staff noted that the range specified for the licensee's instrumentation will cover Levels 1, 2, and 3 as described in Section 4.1 above.

Based on the discussion above, the NRC staff concludes that the licensee's design, with respect to the number of channels and measurement range for its SFP, appears to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.2 Design Features: Arrangement

In its OIP, the licensee stated that the primary instrument channel level sensing components will be located near the north wall of the SFP, and the backup instrument channel level sensing components will be located near the south wall of the SFP, approximately 78 ft. from the primary instrument channel. Additionally, in its OIP, the licensee stated, in part, that:

> The two SFP level instrument channels will be installed in diverse locations, arranged in a manner that provides reasonable protection of the level indication function against missiles that may result from damage to the structure over the SFP. Channel separation (independence) will be provided as part of the design of the SFP level instrumentation. SFP level sensor probes will be installed near the north and south walls of the SFP. Sensor conditioning electronics and battery backup will be located in the Primary Auxiliary Building. Level indication will be located approximately 300 feet away from the SFP. The SFP and sensor conditioning electronics will be separated by a reinforced concrete wall(s) that will provide suitable radiation shielding for the electronics. These locations will provide protection against missiles and will not interfere with SFP activities. Cabling for power supplies and indications for each channel will be routed in separate conduits for each channel.

In its OIP, the licensee also provided a sketch with a plan view of the SFP level instrumentation location. The NRC staff reviewed this sketch and noted that the SFP level instrument probes are located on the north and south walls of the SFP and from there the cables are routed separately to the display locations.

During the onsite audit, the NRC staff walked down the SFP area and the primary and back-up cable route. The staff walked down the PAB where the displays, control boxes and uninterruptible power supply (UPS) are located. From the PAB, the staff visited the SFP area which is the location for the SFP level instrumentation sensor probe and the exit point from the SFP area to the PAB.

The NRC staff concludes that there should be sufficient channel separation within the SFP area between the primary and back-up level instruments, sensor electronics, and routing cables to provide protection against a loss of indication of SFP level due to missiles that may result from damage to the structure over the SFP.

Based on the discussion above, the NRC staff concludes that, if implemented appropriately, the licensee's proposed arrangement for the SFP level instrumentation appears to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.3 Design Features: Mounting

In its OIP, the licensee stated that the mounting of the SFP level instrumentation will be seismic Class 1. The licensee also stated that installed equipment will be seismically qualified to withstand the maximum seismic ground motion considered in the design of the plant area in which it is installed.

In letter dated December 19, 2014 (ADAMS Accecssion No. ML14353A047), the licensee stated that all SFPIS equipment will be designed in accordance with the Point Beach SSE design requirements. The vendor, Westinghouse, has evaluated the structural integrity of the mounting bracket in calculation CN-PEUS-13-28. The GTSTRUDL model, used by Westinghouse to calculate the stresses in the bracket assembly, considers load combinations for the dead load, live load and seismic load on the bracket. The reactionary forces calculated from these load become the design inputs to design the mounting bracket anchorage to the refuel floor to withstand a SSE.

Regarding seismic loads, the licensee stated that the seismic loads are obtained from Point Beach's response spectra. The following method was used in determining the stresses on the bracket assembly: Frequency analysis, taking into account the dead weight and the hydrodynamic mass of the structure, is performed to obtain the natural frequencies of the structure in all three directions. The SSE response spectra analysis is performed to obtain members stresses and support reactions. Model responses are combined using the ten percent method per NRC Regulatory Guide 1.92, Rev. 1, "Combining Modal Responses and Spatial Components in Seismic Response Analysis." This method is endorsed per Appendix A.5 of the Point Beach UFSAR. The seismic loads for each of the three directions are combined by the square root of the sum of squares (SRSS) method. Sloshing analysis is performed to obtain liquid pressure and its impact on bracket design. The seismic results are combined with the dead load results and the hydrodynamic pressure results in absolute sum. These combined results are compared with the allowable stress values.

Regarding sloshing, the licensee stated that sloshing forces were obtained by analysis. The TID-7024, Nuclear Reactors and Earthquakes, 1963, by the U.S. Atomic Energy Commission, approach has been used to estimate the wave height and natural frequency. Horizontal and vertical impact force on the bracket components was calculated using the wave height and natural frequency obtained using TID-7024 approach. Using this methodology, sloshing forces have been calculated and added to the total reactionary forces that would be applicable for bracket anchorage design. The analysis also determined that the level probe can withstand a credible design-basis seismic event. During the design-basis event, the SFP water level is expected to rise and parts of the level sensor probe are assumed to become submerged in borated water. The load impact due to the rising water and submergence of the bracket components has also been considered for the overall sloshing impact. Reliable operation of the level measurement sensor with a submerged interconnecting cable has been demonstrated by analysis of previous Westinghouse testing of the cable, and the vendor's cable qualification. Boron build up on the probe has been analyzed to determine the potential effects on the sensor.

The licensee also stated that the following Westinghouse documents provide information with respect to the design criteria used, and a description of the methodology used to estimate the total load on the device.

a. CN-PEUS-13-28 - Pool-side Bracket Seismic Analysis

b. WNA-TR-03149-GEN - Sloshing Analysis

c. EQ-QR-269, WNA-TR-03149-GEN, EQ-TP-353 - Seismic Qualification of other components of SFPI

The licensee stated that Point Beach specific calculation NEE-009-CALC-006, "Anchorage Qualification for Spent Fuel Pool Instrumentation System Upgrades," provide the qualification for the anchorage of the SFPIS equipment. The design criteria used in this calculation meets the requirements to withstand two times the SSE and will meet the Point Beach seismic Class 1 installation requirements. The methods used in the calculation follow IEEE Standard 344-2004 and IEEE Standard 323-2003 for seismic qualification of the instrumentation.

The licensee further stated that the level sensor, which is one long probe, will be suspended from the launch plate via coupler/connector assembly. The launch plate is a subcomponent of the bracket assembly, which is mounted to the refuel floor via anchors. In addition, the licensee stated that the bracket assembly that supports the sensor probe and launch plat will be mechanically connected to the SFP structure. The mechanical connection consists of four concrete expansion anchors that will bolt the bracket assembly to the SFP structure via the base plate. The concrete expansion anchors will be designed to withstand SSE and will meet the Point Beach seismic installed requirements. The qualification details of the bracket are provided in Westinghouse's pool-side bracket seismic analysis CN-PEUS-13-28 and the qualification of the anchorage to the floor is provided in Point Beach specific calculation NEE-009-CALC-006, "Anchorage Qualification for Spent Fuel Pool Instrumentation System Upgrades."

As part of the onsite audit, the staff reviewed calculations CN-PEUS-13-28, "Seismic Analysis of the SFP Mounting Bracket at Pont Beach Units 1 & 2 and Saint Lucie Units 1 &2," Revision 2, and WNA-TR-03149-GEN, "SFPIS Standard Product Final Summary Design Verification Report," Revision 1. Westinghouse letter LTR-SEE-II-13-47 dated January 15, 2014, "Determination if the Proposed Spent Fuel Pool Level Instrumentation can be sloshed out of the Spent Fuel Pool during a Seismic Event," Revision 0, stated that if the bracket is constructed so that it can withstand certain minimum drag force (in lbf.), then the instrument will stay in the pool. The staff reviewed calculation CN-PEU-13-28 and noted that the bracket's vertical sloshing pressure was calculated to be greater than the minimum required force. This pressure is bounded by Westinghouse analysis. The staff also reviewed drawings PB22638 and PB22639, "Spent Fuel Pool Mounting Bracket Plan Sections and Details," Revision 2, PB22644 and PB22645, "Spent Fuel Pool Instrumentation System Architecture," Revision 2, and PB31EEIC403009, "Electrical Layout Auxiliary Building Area #6 Elevation 66' 0," Revision 10. The staff also walked down the SFP area and the primary and backup cable route.

In letter dated December 19, 2014, the licensee stated that the following Westinghouse documents provide the analyses used to verify the design criteria and describe the methodology for seismic testing of the SFP instrumentation and electronics units, inclusive of design basis maximum seismic loads and hydrodynamic loads that could result from pool sloshing and other effects that could accompany such seismic forces: 1) CN-PEUS-13-28, "Pool-Side Bracket Seismic Analysis," 2) WNA-TR-03149-GEN, "Sloshing Analysis," and 3) EQ-QR-269, "WNA-TR-03149-GEN, EQ-TP-353 - Seismic Qualification of other components of SFPI." No equipment failure were noted as a result of seismic test runs. Seismic test data has been documented in the seismic test reports, referenced above. Point Beach specific calculation NEE-009-CALC-006, "Anchorage Qualification for Spent Fuel Pool Instrumentation System Upgrades," addresses the seismic qualification of the SFPIS equipment to the primary building structure. The design criteria used in their calculation satisfies the requirements to withstand two times the SSE and will meet the Point Beach seismic installation requirements for mounting the readout displays in the PAB.

The licensee also stated that the Westinghouse documents provide the analyses used to verify the design criteria and describe the methodology for seismic testing of the SFP instrumentation and electronic units, inclusive of design basis maximum seismic loads and hydrodynamic loads that could result from pool sloshing and other effects that could accompany such seismic forces. Point Beach specific calculation NEE-009-CALC-006, "Anchorage Qualification for Spent Fuel Pool Instrumentation System Upgrades," addresses the seismic qualification of the SFPIS equipment to the primary building structure. The design criteria used in this calculation satisfies the requirements to withstand two times the SSE and will meet the Point Beach seismic installation requirements for mounting the readout displays in the PABs. During the onsite audit, the staff reviewed Calculation NEE-009-CALC-006, "Anchorage Qualification for Spent Fuel Pool Instrumentation System Upgrades;" Revision 0, and drawings 10116D39 Sheets 1 and 2, "Point Beach Spent Fuel Pool Instrumentation System Architecture." The staff noted that the licensee appears to adequately describe the design inputs and methodology used to qualify the structural integrity of the affected structures/equipment.

The NRC staff also walked down the SFP areas and the primary and back-up cables route. The walk down started at the PAB where the display, control boxes and UPS are located. From the PAB, the staff walked down the SFP area which is the location of the SFP level instrumentation sensor probe and the exit point from the SFP area to the PAB.

Based on the discussion above, the NRC staff concludes that the licensee's proposed mounting design appears to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.4 <u>Design Features: Qualification</u>

In its OIP, the licensee stated, in part, that:

> Temperature, humidity and radiation levels consistent with conditions in the vicinity of the SFP and the area of use considering normal operational, event and post-event conditions for at least seven days post-event, or until off-site resources can be deployed by the mitigating strategies resulting from Order EA-

12-049 will be addressed in the engineering and design phase. Examples of post-event (beyond-design-basis) conditions that will be considered are:

- Radiological conditions for a normal refueling quantity of freshly discharged (100 hours) fuel with the SFP water level 3 as described in this order,
- Temperatures of 212 degrees F and 100% relative humidity environment,
- Boiling water and/or steam environment, and
- A concentrated borated water environment

In addition, in its OIP, the licensee stated, in part, that:

> Both channels will be reliable at temperature, humidity, and radiation levels consistent with the spent fuel pool water at saturation conditions for an extended period. Post event temperature at sensors located above the SFP is assumed to be 212°F. Post event humidity in the Auxiliary Building near and above the SFP is assumed to be 100% with condensing steam. Equipment will be qualified for expected conditions at the installed location assuming that normal power is unavailable and that the SFP has been at saturation for an extended period. Equipment located in the vicinity of the SFP will be qualified to withstand peak and total integrated dose radiation levels for its installed location assuming that post event SFP water level is equal to Top of Rack for an extended period of time.

By letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), the licensee stated that Westinghouse qualified the components (probe, connector, cable) of the SFPIS located in the SFP area to the beyond-design-basis environment. Components of the system were subject to beyond design basis conditions of heat and humidity, thermal, and radiation aging mechanisms. This testing confirmed functionality of these system components under these beyond design basis environment conditions. Westinghouse performed testing to ensure aging of the components in the SFP area will not have a significant effect on the ability of the equipment to perform following a plant design-basis earthquake. Reports with the test results document compliance to the order.

Subsequent to Westinghouse's environmental testing and placing instrument in service at Point Beach, Westinghouse identified a potential condition under evaluation which may warrant an upgrade of coax connections in the SFP area. This potential condition was documented in the site's corrective action program. (Reference Westinghouse documents EQ-TP-351, WNA-TR-03149-GEN, and EQ-TP-354 for description of qualification methods.) Westinghouse qualified the system components (display panel, sensor) that reside in the mild environment conditions to determine that components can satisfactorily perform to those conditions. Westinghouse has determined that aging does not have a significant effect on the ability of the equipment to perform following a plant design-basis earthquake. Reports with the test results document compliance to the order. (Reference Westinghouse documents EQ-QR-269, WNA-TR-03149-GEN for description of specific methods.) For shock and vibration, the licensee stated that SFPIS pool side brackets were analyzed for SSE design requirements per NRC Order EA-12-051 and NEI 12-02 guidance. As provided by NRC Order EA-12-051, the NEI 12-02 guidance and as clarified by the NRC interim staff guidance, the probe, coaxial cable, and the mounting brackets are "inherently resistant to shock and vibration loadings." As a result, no additional shock and vibration testing is required for these components. The SFPIS pool side brackets for both the primary and backup Westinghouse SFP measurement channels will be permanently installed and fixed to rigid refueling floors, which are seismic Class 1 structures. The SFPIS components, such as level sensor and its bracket, display enclosure and its bracket, were subjected to seismic testing, including shock and vibration test requirements. The results for shock and vibration tests were consistent with the anticipated shock and vibration expected to be seen by mounted equipment. The level sensor electronics are enclosed in NEMA-4X housing. The display electronics panel utilizes a NEMA-4X rated stainless steel housing as well. These housing will be mounted to the seismically qualified wall and will contain the active electronics, and aid in protecting the internal components from vibration induced damage. Westinghouse has seismically qualified the SFPI instrument and its components. Document CN PEUS-13-28 describes pool-side bracket seismic analyses, and documents EQ-QR-269, WNA-TR-03149-GEN, EQ-TP-353 describe remaining seismic qualifications of the instrument component. With the instrument being seismically qualified and installed, the instrument is assumed to maintain reliable and accuracy from measurement to display.

During the onsite audit, the staff reviewed Calculation N-89-024, "Dose Rates at Elev. 66' From Opt. Fuel Assembly in Reactor Cavity under Varying Depth of Water," dated May 1, 1989, and Engineering Evaluation 278718, "Evaluate Primary Auxiliary Building (PAB) Scenario for Fukushima Coping," dated April 2, 2013. The staff concluded that the calculated integrated doses, temperature, and humidity for both the normal condition and post-BDB event for the locations where the SFPIS located appear to be bounded by the acceptable limits. The staff also concluded that Point Beach utilizes the 90 degree probe connector. This connector type is qualified for 10 years as described in Westinghouse letter LTR-SFPI-15-34.

In the December 19, 2014 letter, the licensee further stated that environmental conditions for SFPIS components installed in the SFP area at Point Beach are bounded by the test conditions. The radiation total integrated dose (TID) for BDB at the floor above the SFP when the SFP water level is at Level 3 is 9.4E+06R based on the results of calculation N-89-024, "Dose Rates at Elev. 66' from Fuel Assembly in Reactor Cavity During Varying Depth of Water." The results of calculation N-89-024 were adjusted using a conservative "1/r" distance correction to reflect the difference in the location of the top of the fuel rack in the SFP and the location used in the calculation (El. 55'2") and a conservative power factor of 1.3 to reflect change in fuel assembly source term due to power uprate. The BDB radiation value to which the Westinghouse equipment is qualified to is 1E+09 Rad for the probe stainless steel cable in the SFP and 1E +07 Rad for the equipment above the pool, per Section 5.1.2 of WNA-TR-03149-GEN. When the SFP water is at level 3, the only components of the SFPI that are exposed to high radiation are the stainless steel probe and anchor. These components are manufactured from materials that are resistant to radiation effects and which can withstand a 40 year radiation dose. The radiation TID for BDB conditions at the floor above the SFP when the SFP water level is at Level 2 is 8E+01 Rad based on the results of calculation N-89-024 and corrected in the same manner described earlier. Level sensor probe, coax coupler and connector assembly, launch plate and pool side bracket assembly, coax cable are designed and qualified to operate reliably. Seismic qualification testing performed by Westinghouse along with the technical evaluations perform by Westinghouse confirm that the SFPIS meets the seismic requirements of the vendor's design specification. Westinghouse's design specification satisfies the Point Peach installation requirements to withstand a SSE.

In addition, the licensee stated that components of the system (i.e., bracket, transmitter enclosure, display enclosure, and readout display) will be permanently installed to meet the requirement to withstand a SSE and will meet the Point Beach seismic installation requirements. Westinghouse has analyzed the pool side bracket to withstand design basis SSE. Other components of the SFPIS were subjected to shock and vibration during seismic testing and met the requirements necessary for mounted equipment. The sloshing calculation performed by Westinghouse was reviewed for a design-basis seismic event and found acceptable. Sloshing forces were taken into consideration for the anchorage design of the pool side bracket to ensure the bracket is rigidly mounted to include sloshing affects.

During the onsite audit, the staff verified the licensee's conclusions that environmental qualification of SFPIs components are bounded by the test conditions. The staff reviewed Calculation N-89-024, "Dose Rates at Elev. 66' from Opt. Fuel Assembly in Reactor Cavity During Varying Depths Water," dated May 1, 1989, and Engineering Evaluation 278718, "Evaluate PAB Scenarios for Fukushima Coping," dated April 2, 2013. The staff concluded that the calculated integrated doses, temperature, and humidity for both the normal condition and post-BDB event for the locations where the SFPIS are located appear to be bounded by the acceptable limit.

During the onsite audit, the NRC staff also inquired about an assessment of potential susceptibilities of electromagnetic interferences and radio-frequency interference (RFI) in the areas where the SFP instruments are located and how to mitigate those susceptibilities. In response, the licensee stated that the SFPI has been tested by both the vendor and post-installation testing via site work plan 40247116-20. The site work plan document determined fluctuation as "SAT" for keying the radios at several distances (10 ft., 8 ft., 6 ft., 3 ft., & 1 ft.) from both the level indicating transmitter and level indicator. LI-40A at 3 ft. and 1 ft., noted change were 0.1 ft. and 0.54 ft., respectively. LI-40B at 1 ft. noted change was 0.12 ft. The acceptance criteria states that an action does not cause signal disturbance (waveform at the transmitter is normal and the display at the electronics cabinets does not fluctuate excessively). Engineer change (EC) 276803 states that, "Westinghouse position is that the standard base product meets criterion B and any additional modifications required to meet A could be purchased or installed by the sites based on the testing reports. Criterion A equipment shall continue to operate during and after the event with no degradation or loss of function. Criterion B only requires the equipment to operate following the event. NextEra chose to purchase most of the criterion A modification. This includes routing the cable in dedicated conduit, installing an enclosure at the launch plate to house the coupler, 90° connector and coax cable, an enclosure to house the level sensor lead and a separate enclosure at the level display to house a second surge suppressor and breaker. This second enclosure is where the main power feed connects plus the signal can be filtered prior to entering the main level display enclosure." Although the above tests results were satisfactory, to ensure awareness to the sensitivity, the site initiated work orders to mark the indicator as RFI sensitive. Work orders have been generated at the site to mark the areas. The NRC staff concludes that the licensee's response appears to be consistent with NEI 12-02 guidance.

Based on the discussion above, the NRC staff concludes that the licensee's proposed instrument qualification process appears to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.4.1 Augmented Quality Process

Appendix A-1 of the guidance in NEI 12 02 describes a quality assurance process for non-safety systems and equipment that are not already covered by existing quality assurance requirements. In JLD-ISG-2012-03, the NRC staff found the use of this quality assurance process to be an acceptable means of meeting the augmented quality requirements of Order EA-12-051.

In its OIP, the licensee stated that the augmented quality requirements, similar to those described in the Point Beach Quality Assurance Topical Report, and to those applied to fire protection, will be applied to this project.

Based on the discussion above, the NRC staff concludes that this approach appears to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.4.2 Instrument Channel Reliability

Section 3.4 of NEI 12-02 states, in part:

> The instrument channel reliability shall be demonstrated via an appropriate combination of design, analyses, operating experience, and/or testing of channel components for the following sets of parameters, as described in the paragraphs below:
>
> - Conditions in the area of instrument channel component use for all instrument components,
> - Effects of shock and vibration on instrument channel components used during any applicable event for only installed components, and
> - Seismic effects on instrument channel components used during and following a potential seismic event for only installed components.

Equipment reliability performance testing was performed to (1) demonstrate that the SFP instrumentation will not experience failures during beyond-design-basis (BDB) conditions of temperature, humidity, emissions, surge, and radiation, and (2) to verify those tests envelope the plant-specific requirements.

The NRC staff reviewed the Westinghouse SFP level instrumentation's qualification and testing during the vendor audit for temperature, humidity, radiation, shock and vibration, and seismic (ADAMS Accession No. ML14211A346). The staff further reviewed the anticipated Point Beach environmental conditions during the onsite audit.

Based on the evaluation above, the NRC staff concludes that the licensee's proposed instrument qualification process appears to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.5 Design Features: Independence

In its OIP, the licensee stated that the primary instrument channel will be redundant to and independent of the backup instrument channel. The licensee also stated that independence will be obtained through separation of the sensors, indication, backup battery power supplies, associated cabling and channel power feeds.

In its letter dated July 3, 2013 (ADAMS Accession No. ML13186A012), the licensee stated, in part, that the permanently installed primary and backup instrument channels will be redundant to and independent of each other with respect to physical separation and the normal electrical power sources are from separate trains. The physical and electrical separation minimizes the potential for a single fault to adversely affect both channels. Specifically, the licensee stated:

> The level sensors, located near the north-east corner and south-east corners of the SFP, will be physically separated to the extent practical by a distance greater than the shortest length of a pool side. The length of the shortest side of the SFP is approximately 18 feet long. The level sensors, with the primary located near the north-east corner of the pool and the backup located near the south-east corner of the pool, exceed the length of the shortest side of the SFP. The horizontal separation minimizes a common cause event in the area of the SFP from adversely affecting both channels. The level transmitters, one per channel, will be physically separated from each other and are located two elevations below the level sensors in the Primary Auxiliary Building (PAB). The third component, the level processor cabinets, one per channel, which includes the display and uninterruptible power supply (UPS), will be located on the same PAB plant elevation as the transmitter and are physically separated from each other by a horizontal distance exceeding 15 feet.
>
> All interconnecting cable and raceway between the level sensor and transmitter and transmitter and processor will be routed such that the primary channel components are located and routed in the northern portion of the PAB, whereas the backup channel components are located and routed in the southern portion of the PAB. The cabling for each channel will be located in physically independent raceways. These separation distances are well in excess of the design guidelines for the Point Beach Nuclear Plant (PBNP) and minimize the potential for a single fault to affect both channels.

By letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), the licensee stated that the primary channel will be powered from a 120 Vac emergency lighting panel, 37-E. This panel can be aligned to the Unit 2 Train A backup 1E emergency power supply via MCC 2B-32, which is fed from 2B-03 and 2A-05, and can be aligned to EDG G-02 (normal) or EDG-G-01 (alternate). Panel 37-E is located in the PAB, accessible from plant elevation 66 ft. and is located on the north wall near the SFP. The backup level channel is powered from 120 Vac emergency lighting panel, 31-E. Panel 31-E is located in the PAB, accessible from plant Elevation 66 ft. and is located on the south wall near the SFP. During the onsite audit, the NRC staff verified that the power supply source for each channel is independent by reviewing drawings PB07322, "Simplified Electrical Power Distribution," Revision 7, and MDB 3.2.10, "Emergency Lighting Panels -- Panel 31E and Panel 37E," Revisions 8 and14.

Based on the discussion above, the NRC staff concludes that the licensee's proposed design, with respect to instrument channel independence, appears to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.6 Design Features: Power Supplies

In its OIP, the licensee stated, in part, that both channels will be powered from dedicated batteries and local battery chargers. The battery chargers for both channels will normally be powered from non-safety related 120 Vac power source. The minimum battery life of 72 hours will be provided, and the battery systems will include provisions for readily available battery replacements should the battery charger be unavailable following the event. In the event of a loss of normal power, the battery chargers could be connected to another suitable power source.

By letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), the licensee stated that Westinghouse report, WNA-CN-00300-GEN, provides the results of the calculation depicting the battery backup duty cycle. This calculation demonstrates that battery capacity is 4.22 days to maintain the level indicating function to the display location, located in the 26 ft. PAB at Point Beach. The FLEX designated guidelines for Point Beach is 3 days; therefore, the results of the calculation meet the requirements laid out by the site. The NRC staff reviewed the battery backup duty cycle calculation during the vendor audit at Westinghouse and found it acceptable.

Based on the discussion above, the NRC staff concludes that the licensee's proposed power supply design appears to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.7 Design Features: Accuracy

In its OIP, the licensee stated, in part, that instrument channels will be designed such that they will maintain their design accuracy following a power interruption or change in power source without recalibration. Accuracy will consider SFP conditions, e.g., saturated water, steam environment, or concentrated borated water. Additionally, instrument accuracy will be sufficient to allow trained personnel to determine when the actual level exceeds the specified lower level of each indicating range (levels 1, 2 and 3) without conflicting or ambiguous indication. The accuracy will be within the resolution requirements of Figure 1 of NEI 12-02.

By letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), the licensee stated that Westinghouse documents WNA-CN-00301-GEN and WNA DS 02957-GEN describe the channel accuracy under both (a) normal SFP level condition and (b) at the Beyond Design Basis (BDB) conditions that would be present if SFP level were at Level 2 and Level 3 data points. Each instrument channel will be accurate to within +/- 3 in. during normal SFP level conditions. The instrument channels will retain this accuracy after BDB conditions, in accordance with the above Westinghouse documents. This value is within the channel accuracy requirements of the order (+/- 1 foot). The Westinghouse document WNA-TP-04709-GEN describes the methodology for routine testing/calibration verification and calibration methodology. This document also specifies the required accuracy criteria under normal operating conditions.

Point Beach calibration and channel verification procedures will follow the guidance and criteria provided in this document. Instrument channel calibration will be performed if the level indication reflect a value that is outside the acceptance and established in the Point Beach calibration and channel verification procedures. Instrument channel loop accuracy and set point deviation/error are determined using Point Beach design guide, DG-101 for safety related instruments. The methodology used to determine the setpoint deviation in this standard is consistent with ANSI/ISA-67.04.01-2000. Per this methodology, since drift value was not specified by the vendor, a default random drift value of +/-1 percent of span (or +/- 1 percent of full scale, for conservatism) for mechanical components was assigned. A setting tolerance of twice the reference accuracy, which is a typical value, was applied to the indication to yield an overall setting tolerance of +/-2 percent of full scale. This value will be used for the calibration procedure being developed for this instrument loop. The resultant non-negligible terms (Reference Accuracy, Drift, Readability, Measurement and Test Equipment Effect, and Setting Tolerance) are all random terms, and will be combined using the SRSS methodology given in DG-101. The maximum deviation introduced by the indicator, in percent of full span, is computed. Calibration will be performed once per refueling cycle for Point Beach. Per Westinghouse document WNA-TP-04709-GEN, calibration on a SFP channel is to be completed within 60 days of a planned refueling outage considering normal testing scheduling allowances (e.g. 25 percent), which is consistent with the NEI 12-02 guidance.

The NRC staff noted that Westinghouse specifies channel accuracy of +/- 3 in. The licensee channel accuracy as stated in its letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), Attachment 2, Item 17, "Channel Accuracy," states that channel accuracy is +/- 6 in. This is not consistent with the vendor specified accuracy. During the onsite audit, the staff reviewed calibration procedure ICP 03.017, "Calibration of Spent Fuel Pool Level Instrumentation Systems," Revision 0, and it also requires that operaotrs verify the channel accuracy to be within +/- 3 in. Therefore, the staff questioned the inconsistency. The licensee responded that the operating log out of service requirement for the instruments is currently based on the order requirement and not on the vendor's recommendation for required accuracy. Therefore, the current guidance in the operating logs has a +/-6 in. channel deviation as the setpoint for declaring the channels as not functioning correctly. The licensee generated action report, AR 2053292 to document the difference in acceptance criteria and revise the operating logs such that the SFP channels are declared nonfunctioning at the vendor recommended +/- 3 in. deviation, which is consistent with Westinghouse's specified accuracy.

Based on the discussion above, the NRC staff concludes that the licensee's proposed instrument accuracy appears to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.8 Design Features: Testing

In its OIP, the licensee stated, in part, that the instrument channel design will provide for routine testing and calibration consistent with Order EA-12-051 and the guidance in NEI 12-02.

By letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), the licensee stated that Westinghouse calibration procedure WNA-TP-04709-GEN and functional test procedure WNA-TP-04613 describe the capabilities and provision of SFPI periodic testing and calibration, including in-situ testing. Point Beach will utilize the Westinghouse calibration procedure for the functional check at the pool side bracket. The level display by the channel will be verified per Point Beach administrative and operating procedure, as recommended by Westinghouse vendor technical manual WNA-GO-00127-GE. If the level is not within the required accuracy per Westinghouse recommended tolerance in WNA-TP-04709-GEN, channel calibration will be performed. Functional check will be performed per Westinghouse functionality test procedure WNA-TP-04613-GEN at the Westinghouse recommended frequency. Calibration tests will be performed per Westinghouse calibration procedure WNA-TP-04709-GEN at the Westinghouse recommended frequency. Point Beach will develop preventive maintenance tasks for the SFPI per Westinghouse recommendations identified in the technical manual WNA-GO-00127 to assure that the channels are fully functional when needed.

The staff noted that the licensee developed a program for testing, calibration, and maintenance. This program appears to be consistent with those recommended by Westinghouse. By comparing the levels in the instrument channels and the acceptance criteria described above, the operators can determine if recalibration or troubleshooting is needed.

The NRC staff concludes that the licensee's proposed design, with respect to routine in-situ instrument channel functional and calibration tests, appears to be consistent with NEI 12-02, as endorsed by the ISG, should and adequately address the requirements of the order.

4.2.9 Design Features: Display

In its OIP, the licensee stated that remote indication will be provided in the PAB as it will provide an indication that will be accessible during post-accident conditions.

By letter dated December 19, 2014 (ADAMS Acccession No. ML14353A047), the licensee stated that the location of the SFP wide range level instrumentation displays will be on the 26 ft. elevation of the PAB near the C-59 waste disposal control panel. The displays will be approximately 40 ft. below the level sensors in an adjacent area, outside the area surrounding the SFP floor and are physically separated from each other within the PAB. They will be physically protected from the environmental and radiological conditions resulting from a BDBEE. Westinghouse documents EQ-QR-269 and WNA-TR-03149-GEN provide qualification details for the SFPI components. Site specific calculation 2013-0020, "PAB Scenarios for Fukushima Coping," determined the 140°F temperature and 95 percent humidity for the location of the equipment at the 26 ft. elevation of the PAB was acceptable for the site specific conditions. Analysis was performed using a commercial shielding program (MicroShyshine) to determine the expected dose rate in the 26 ft. elevation where the equipment would be located. The fuel assembly data (dimensions and density) in N-89-024 was used; however, the fuel assembly activity was calculated using the data contained in Table 14.3.5-1, "Core Activities." The data in Table 14.3.5-1 is at shutdown and is based on a core power level of 1811 MWt. The source term for the fuel assembly was calculated by dividing the core activity by the number of fuel assemblies in the core and then decaying it for 65 hours. The geometry modeled in the program was with the fuel assembly in the SFP storage location with one foot of water over the top of the fuel, at the 46 ft. elevation concrete floor with a thickness of 18" and the dose point at the 30 ft. elevation (four feet above floor level). The dose point was placed at a lateral distance of 150 ft. from the center of the fuel assembly. The calculated dose rate was 8 mrem/hr for a 40 fuel assembly array. The licensee concluded based on this analysis that the equipment is bounded by the testing performed by Westinghouse and the location is accessible for personnel during a BDBEE.

The licensee also stated that the 26 ft. elevation in the PAB is contained within a seismic Class 1 structure that has multiple access routes. Normal access is provided from the south through the radiation protection checkpoint. Alternate access routes are available from the Unit 1 turbine hall to the PAB and up the stairs to the C-59 panel area. Another alternate access route is available from the Unit 2 turbine hall to the PAB and up the stairs to the C-59 area. Environmental conditions on the 26 ft. and 8 ft. levels are expected to remain habitable and accessible at saturation conditions in the SFP. Calculation 2013-0020 indicated that with an outside air temperature of 105°F that the temperature in the C-59 area reached a maximum of 105°F in the first 24 hours assuming the SFP reached saturation conditions in 10 hours. The licensee further stated that the 26 ft. elevation near the C-59 panel is a designated watch station and manned with a qualified auxiliary operator during normal operation conditions. During a BDBEE, qualified operators would be implementing the FLEX strategies near the wide range level displays and would be available to obtain readings and relay that information to the control room with minimal delays. In the event that no operators are in the vicinity of the level displays it is reasonable to assume that individuals could be dispatched from the control room or the technical support center, obtain readings and report the level to the control room in less than 1 hour. This is based on transient time from the control room to the C-59 area, which is less than 15 minutes including time to process through the radiation checkpoint. Hand held radios, person to person contact or the PBX phone system are communication systems available to transmit the information. During the onsite audit, the NRC staff verified the above information during a walk down of the SFP area.

Based on the discussion above, the NRC staff concludes that the licensee's proposed location and design of the SFP instrumentation displays, including prompt accessiblility and the location remaining habitable, appear to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.3 Evaluation of Programmatic Controls

Order EA-12-051 specified that the SFPI shall be maintained available and reliable through appropriate development and implementation programmatic controls, including training, procedures, and testing and calibration. Below is the NRC staff's assessment of the programmatic controls for the SFPI.

4.3.1 Programmatic Controls: Training

In its OIP, the licensee stated, in part, that the SAT process will be used to identify the population to be trained and to determine both the initial and continuing elements of the required training. Training will be completed prior to placing the instrumentation in service.

The NRC staff concludes that the licensee's proposed plan to train personnel in the operation, maintenance, calibration, and surveillance of the SFPI and the provision of alternate power to the primary and backup instrument channels, including the approach to identify the population to be trained appear to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.3.2 Programmatic Controls: Procedures

In its OIP, the licensee stated that procedures will be developed using guidelines and vendor instructions to address the maintenance, operation, and abnormal response issues associated with the new SFPI.

By letter dated February 28, 2014 (ADAMS Accession No. ML14059A086), the licensee stated that the modification review process will be used to ensure all necessary procedures are developed for maintaining and operating the SFPIs after installation. These procedures will be developed in accordance with NextEra procedural controls.

The objectives of each procedural area are described below:

Inspection, Calibration, and Testing - Guidance on the performance of periodic visual inspections, as well as intrusive testing, to ensure that each SFPI channel is operating and indicating level within its design accuracy.

Preventative Maintenance - Guidance on scheduling of, and performing, appropriate preventative maintenance activities necessary to maintain the instruments in a reliable condition.

Maintenance - To specify troubleshooting and repair activities necessary to address system malfunctions.

Programmatic Controls - Guidance on actions to be taken if one or more channels is out of service.

System Operations - To provide instructions for operation and use of the system by plant staff.
Response to Inadequate Levels - Action to be taken on observations of levels below normal level will be addressed onsite using normal procedures and /or FSGs.

During the onsite audit, the licensee supplemented its response by providing a list of procedures to the staff, which are listed below:

- 1-SOP-208Y-L04, "Unit 1 Vital Train B Lighting Panels," Revision 8 - Provides guidance on removing normal power supply to the wide range level indicator.

- 2-SOP-208Y-L03, "Unit 2 Vital Train A Lighting Panels," Revision 9 - Provides guidance on removing normal power supply to the wide range level indicator.

- AOP-8F, "Loss of Spent Fuel Pool Cooling," Revision 20 - Provides guidance during an abnormal condition to reestablish cooling and makeup to the SFP.

- FSG-11, "Alternate SFP Makeup and Cooling"- Provides guidance when AOP-8F is entered during a BDBEE and SFP makeup is required.

- PBF-2031, "Auxiliary Building Log," Revision 107 – Provides the daily surveillance of the wide range level of the SFP.

- OM 3.42, "Control of Wide Range SFP Level Determination," Revision 0 - Provides programmatic requirements for the SFP wide range level indicators and actions to take if one or both instruments are out of service.

- ICP 3.017, "Calibration of SFP Level Instrumentation System," Revision 0 - Provides guidance on performing functional checks and calibration for the SFP wide range level indicators.

The NRC staff reviewed the licensee's list to verify that they have procedures in place to address operation, calibration, testing, and maintenance that will be used for the SFPI. In addition, the staff verified that the SFPI battery will be replaced every 3 years (Work Order 40345881), the level sensor will be replaced every 7 years (Work Order 40345843), and the residual boron buildup around the SFPI will be checked every year (PCR 02044037).

Based on the discussion above, the NRC staff concludes that the licensee's procedure development appears to be consistent with NEI 12-02 guidance, as endorsed by JLDISG-2012-03, and should adequately address the requirements of the order.

4.3.3 Programmatic Controls: Testing and Calibration

In its OIP, the licensee stated, in part, that:

> Processes will be established and maintained for scheduling and implementing necessary testing and calibration of the primary and backup spent fuel pool level instrument channels to maintain the instrument channels at the design accuracy. Testing and calibration of the instrumentation will be consistent with vendor recommendations and any other documented basis. Calibration will be specific to the mounted instrument and the monitor.

By letter dated February 28, 2014 (ADAMS Accession No. ML14059A086), the licensee stated that the SFP instrumentation channel/equipment maintenance/preventative maintenance and testing program requirements to ensure design and system readiness are planned to be established in accordance with Point Beach processes and procedures, and will take in consideration the vendor recommendations to ensure that appropriate regular testing, channel checks, functional tests, periodic calibration and maintenance is performed (and available for inspection and audit). Subject maintenance and testing program requirements are planned to be developed during the SFPI modification design process. Both primary and backup SFP instrumentation channels incorporate permanent installation (with no reliance on portable, post-event installation) of relatively simple and robust augmented quality equipment. Permanent installation coupled with stocking of adequate spare parts reasonably diminishes the likelihood that a single channel (and greatly diminishes the likelihood that both channels) is (are) out-of-service for an extended period of time. Planned compensatory actions for unlikely extended out-of-service events are summarized as follows:

> If 1 channel is out of service, initiate action to restore channel to functional status within 90 days. Initiate an evaluation in accordance with the corrective action program. The evaluation shall determine compensatory actions if a second channel becomes inoperable. The evaluation shall include a planned schedule for restoring the instrument channel(s) to functional status. If 2 channels are out of service, initiate action to restore at least one channel to functional status within 24 hours. Implement compensatory actions for monitoring SFP level within 72 hours. Initiate an evaluation in accordance with the corrective action program. The evaluation shall document compensatory actions taken or planned to be taken to implement an alternate method of monitoring and schedule required actions for restoring the instrumentation channel(s) to functional status.

In addition, the lciensee stated that Point Beach will perform periodic calibration verification and will consider provisions for out of service or non-functional equipment including allowed outage times (AOTs) and compensatory actions.

By letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), the licensee stated that Westinghouse calibration procedure WNA-TP-04709-GEN and functional test procedure WNA-TP-04613-GEN describe the capabilities and provisions of SFPI periodic testing and calibration, including in situ testing. Point Beach will utilize the Westinghouse calibration procedure for the functional check at the pool side bracket. The level displaced by the channels will be verified per the Point Beach administrative and operating procedures, as recommended by Westinghouse vendor technical manual WNA-GO-00127. If the level is not within the required accuracy per Westinghouse recommended tolerance in WNA-TP-04709, channel calibration will be performed. During the onsite audit, the staff reviewed procedure ICP 03.017, "Calibration of Spent Fuel Pool Level Instrumentation Systems," Revision 0, and verified that the licensee will perform periodic calibration, testing, and maintenance as recommended by the vendor.

Based on the discussion above, the NRC staff concludes that the licensee's proposed testing and calibration plan appear to be consistent with NEI 12-02 guidance, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.4 Conclusions for Order EA-12-051

By letter dated December 19, 2014 (ADAMS Accession No. ML14353A047), the licensee stated that they would meet the requirements of Order EA-12-051 by following the guidelines of NEI 12-02, as endorsed by JLD-ISG-2012-03. In the evaluation above, the NRC staff finds that, if implemented appropriately, the licensee has conformed to the guidance in NEI 12-02, as endorsed by JLD-ISG-2012-03. In addition, the NRC staff concludes that if the SFP level instrumentation is installed at Point Beach according to the licensee's proposed design, it should adequately address the requirements of Order EA-12-051.

5.0 CONCLUSION

In August 2013 the NRC staff started audits of the licensee's progress on Orders EA-12-049 and EA-12-051. The staff conducted an onsite audit in June 2015 (ADAMS Accession Nos. ML15117A666 and ML15133A501, respectively). The licensee reached its final compliance date on December 16, 2015, and has declared that both of the reactors are in compliance with the orders. The purpose of this safety evaluation is to document the strategies and implementation features that the licensee has committed to.

Based on the evaluations above, the NRC staff concludes that the licensee has developed guidance and proposed designs that if implemented appropriately should adequately address the requirements of Orders EA-12-049 and EA-12-051. The NRC staff will conduct an onsite inspection to verify that the licensee has implemented the strategies and equipment to demonstrate compliance with the orders.

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Sincerely,

/RA/

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Docket Nos.: 50-266 and 50-301

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