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

August 4, 2016

Mr. David A. Heacock
President and Chief Nuclear Officer
Virginia Electric and Power Company
Dominion Nuclear
500 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: SURRY POWER STATION, UNIT NOS. 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. MF1002, MF1003, MF1004, AND MF1005)

Dear Mr. Heacock:

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 Modifying 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 28, 2013 (ADAMS Accession No. ML13063A181), Virginia Electric and Power Company (Dominion, the licensee) submitted its OIP, for the Surry Power Station, Surry Unit Nos. 1 and 2 (Surry) in response to Order EA-12-049. At six-month intervals following the submittal of its 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 (SE). 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 February 19, 2014 (ADAMS Accession No. ML14002A145), and April 14, 2014 (ADAMS Accession No. ML15096A391), the NRC issued an Interim Staff Evaluation (ISE) and audit report, respectively, on the licensee's progress. By letter dated July 22, 2015 (ADAMS Accession No. ML15209A503), Dominion submitted its compliance letter for Surry, Unit 1. By letter dated January 25, 2016 (ADAMS Accession No. ML16033A353), Dominion submitted its compliance letter for Surry Unit 2, and its Final Integrated Plan (FIP) for Surry, Unit Nos. 1 and 2, in response to Order EA-12-049. Each compliance letter stated that the licensee had achieved full compliance with Order EA-12-049 for the respective unit.

By letter dated February 28, 2013 (ADAMS Accession No. ML13063A013), Dominion submitted its OIP for Surry, Unit Nos. 1 and 2, in response to Order EA-12-051. At six-month intervals following the submittal of its 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 SE. By letters dated November 1, 2013 (ADAMS Accession No. ML13298A625), and April 14, 2015 (ADAMS Accession No. ML15096A391), the NRC staff issued an ISE and audit report, respectively, 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 July 20, 2015 (ADAMS Accession No. ML15205A342), Dominion submitted its compliance letter for Surry Unit Nos. 1 and 2, 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 SE provides the results of the NRC staff's review of Dominion's strategies for Surry. The intent of the SE is to inform Dominion on whether or not its integrated plans, if implemented as described, provide a reasonable path for compliance with 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. ML14273A444). This inspection will be conducted in accordance with the NRC's inspection schedule for the plant.

If you have any questions, please contact Milton Valentin, Orders Management Branch, Surry Power Station Project Manager, at 301-415-2864 or at Milton.Valentin@nrc.gov.

Sincerely,

Mandy K Halter

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

Docket Nos.: 50-280 and 50-281

Enclosure:
Safety Evaluation

cc w/encl: Distribution via Listserv

SURRY POWER STATION, UNIT NOS. 1 AND 2

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UNITED STATES
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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

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

VIRGINIA ELECTRIC AND POWER COMPANY

SURRY POWER STATION, UNIT NOS. 1 AND 2

DOCKET NOS. 50-280 AND 50-281

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 (U.S.). 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” [Reference 4]. 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" [Reference 5]. 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 [Reference 1]. 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," [Reference 2] to the Commission. This paper included a proposal to order licensees to implement enhanced BDBEE mitigation strategies. As directed by Staff Requirements Memorandum (SRM)-SECY-12-0025 [Reference 3], the NRC staff issued Orders EA-12-049 and EA-12-051.

2.1 Order EA-12-049

Order EA-12-049, Attachment 2, [Reference 4] 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 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 August 21, 2012, following several submittals and discussions in public meetings with NRC staff, the Nuclear Energy Institute (NEI) submitted document NEI 12-06, “Diverse and Flexible Coping Strategies (FLEX) Implementation Guide,” Revision 0 [Reference 6] to the NRC to provide 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 and on August 29, 2012, issued its final version of Japan Lessons-Learned Directorate (JLD) Interim Staff Guidance (ISG) JLD-ISG-2012-01, “Compliance with Order EA-12-049, Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events” [Reference 7], endorsing NEI 12-06, Revision 0, with comments, as an acceptable means of meeting the requirements of Order EA-12-049, and published a notice of its availability in the *Federal Register* (77 FR 55230).

2.2 Order EA-12-051

Order EA-12-051, Attachment 2, [Reference 5] 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.
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> 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 [Reference 8] 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" [Reference 9], 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 28, 2013 [Reference 10], and April 30, 2013 [Reference 42] Virginia Electric and Power Company (Dominion, the licensee) submitted its Overall Integrated Plan (OIP) and OIP supplement, respectively, for the Surry Power Station (Surry), Unit Nos. 1 and 2, in response to Order EA-12-049.

By letters dated August 23, 2013 [Reference 11], February 27, 2014 [Reference 12], August 28, 2014 [Reference 13], March 2, 2015 [Reference 14], and August 24, 2015 [Reference 43], the licensee submitted six-month updates to the OIP. By letter dated August 28, 2013 [Reference 15], 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" [Reference 35]. By letters dated February 19, 2014 [Reference 16], and April 14, 2015 [Reference 17], the NRC issued an Interim Staff Evaluation (ISE) and an audit report, respectively, on the licensee's progress.

By letter dated July 22, 2015 [Reference 18], the licensee reported that full compliance with the requirements of Order EA-12-049 was achieved for Surry, Unit No.1. By letter dated January 25, 2016 [Reference 45], Dominion submitted its compliance letter for Surry, Unit No. 2, and its Final Integrated Plan (FIP) for Surry, Unit Nos. 1 and 2, in response to Order EA-12-049. Each compliance letter stated that the licensee had achieved full compliance with Order EA-12-049 for the respective Unit.

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 ac power (ELAP) with loss of normal access to the UHS. Thus, the ELAP with loss to the normal access to 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 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.

Surry, Unit Nos. 1 and 2 are Westinghouse pressurized-water reactors (PWRs) with large dry sub-atmospheric containment buildings. The FIP describes the licensee's three-phase approach to mitigate a postulated ELAP event.

As a result of the extreme natural phenomenon that initiates the extended loss of ac power with loss of normal access to the ultimate heat sink (ELAP/LUHS) event, the reactors trip and the plant will initially stabilize at no-load reactor coolant system (RCS) temperature and pressure conditions. The reactor coolant pumps (RCPs) are assumed to trip due to the loss of electrical power, and natural circulation flow develops in the RCS, with reactor decay heat removal via steam release to the atmosphere through the main steam safety valves (MSSVs) and/or the steam generator (SG) power operated relief valves (PORVs). The turbine-driven auxiliary feedwater (TDAFW) pump at each unit, which starts automatically upon loss of offsite power, provides flow from the emergency condensate storage tanks (ECST) and then from the emergency condensate makeup tanks (ECMT) to the SGs to maintain sufficient SG inventory. Operator actions to verify and throttle AFW flow are required by the emergency operating procedures (EOPs) following an ELAP/LUHS event to control the flow of feedwater to the SGs.

A symmetric RCS cooldown is initiated within the first 2 hours. The RCS is cooled down and depressurized until SG pressure reaches 300 pounds per square inch gage (psig), which corresponds to a core inlet temperature of approximately 422 degrees fahrenheit (°F). The RCS isolation is verified to have occurred automatically, although some RCS leakage would occur, particularly through the RCP seals, which would no longer be cooled during the ELAP event.

The dc bus load stripping is initiated within 45 minutes following a BDBEE to ensure class 1E battery life is extended to 14 hours. Phase 2 portable generators are deployed to repower instrumentation prior to battery depletion.

The Phase 2 FLEX strategy for reactor core cooling and decay heat removal provides an indefinite supply of water for feeding the SGs by deploying the BDB high capacity pump to take suction from the settling pond or the circulating water discharge canal. SG water injection using a portable BDB AFW pump is available through both primary and alternate connection locations when the TDAFW pump becomes unavailable.

The RCS makeup is initiated within 16 hours of the ELAP/LUHS event to ensure natural circulation, reactivity control, and consistent boron mixing in the RCS. The RCS makeup is accomplished using a portable diesel driven beyond design-basis (BDB) RCS Injection pump to replenish RCS inventory and re-establish RCS level in the pressurizer. The water sources are the refueling water storage tanks (RWST) or the portable boric acid mixing tanks.

The Phase 2 FLEX strategy also includes re-powering of vital 120 volt alternating current (Vac) buses within 14 hours using portable 480 Vac diesel generators (DG) via the battery chargers and inverters. Prior to depletion of the Class 1E batteries, selected vital 120 Vac circuits are re-powered to continue to provide key parameter monitoring instrumentation. Portable 120/240 Vac DGs are available as alternates to the 480 Vac DGs.

The Phase 3 strategy for decay heat removal and RCS injection includes using National Strategic Alliance for FLEX Emergency Response (SAFER) Response Center (NSRC) pumps and components as backups to the Phase 2 pumps and water sources, as well as additional pumping and boration capacity. The NSRC pumps provide backup to the BDB high capacity pumps, BDB RCS injection pumps, BDB AFW pumps, boric acid mixing tanks, and the 480 Vac DGs. Additionally, a reverse osmosis/ion exchanger water processing system is provided from the NSRC to provide a method to remove impurities from alternate fresh water supplies to the TDAFW pumps, the BDB AFW pumps, or the BDB RCS injection pumps.

The SFP is a common pool designed for both Unit Nos. 1 and 2. The basic FLEX strategy for maintaining SFP cooling is to monitor SFP level and provide sufficient makeup water to the SFP to maintain the normal SFP level. A calculation has determined that with no operator action following a loss of SFP cooling at the maximum design heat load, the SFP reaches 212 °F in approximately 12 hours and boils off to a level 10 feet above the top of fuel in 51 hours from initiation of the event. The Phase 1 coping strategy for spent fuel pool cooling is to monitor SFP level using instrumentation installed as required by NRC Order EA-12-051.

The Phase 2 strategy is to initiate SFP makeup within 24 hours using the emergency SFP makeup line either from the BDB high capacity pump through the BDB SFP makeup connection or, alternately, through the fire protection (FP) system which feeds the emergency SFP makeup line from the yard fire main loop directly. Additionally, in accordance with the guidance provided in NEI 12-06, spray nozzles and sufficient hose length required for the SFP spray option are located in the BDB storage building.

For Phase 3 SFP cooling, additional low pressure/high flow pumps are available from the NSRC as a backup to the onsite BDB high capacity pumps.

During an ELAP/LUHS, containment cooling is also lost. Therefore, containment temperature and pressure slowly increases. Structural integrity of the reactor containment building due to increasing containment pressure is not challenged during the first several weeks of a BDB 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. Conservative evaluations have concluded that containment temperature and pressure remains below containment design limits and that key parameter instruments subject to the containment environment remain functional for a minimum of seven days. Therefore, actions to reduce containment temperature and pressure to ensure continued functionality of the key parameters are not required immediately and utilize offsite equipment during Phase 3.

During Phase 3, necessary actions to reduce containment temperature and ensure continued functionality of the key parameters utilize existing plant systems powered by offsite equipment. The portable 4160 Vac power is needed to operate various station pumps. The portable 4160

Vac generators and a distribution panel for each unit are brought in from the NSRC in order to supply power to either of the two Class 1E 4160 Vac buses on each unit. 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. If service water (SW) is not available from the circulating water intake canal, then low pressure/high flow diesel-driven pumps (up to 5,000 gallons per minute (gpm)) from the NSRC are available to provide flow to existing site heat exchangers to facilitate heat removal from the containment atmosphere. Several options were evaluated to provide operators with the ability to reduce the containment temperature. Each of these options require the restoration of multiple support systems to effectively remove heat from the containment and reduce containment temperature and pressure. The ventilation cooling is the preferred method for reducing containment temperature and establishes containment ventilation by either establishing containment air recirculation fan (CARF) cooling or establishing control rod drive mechanism (CRDM) cooling. The spray option is also available to spray water into the containment using the containment recirculation spray (RS) system utilizing clean water from the RWST or the settling pond.

Below are specific details on the licensee's strategies to restore or maintain core cooling, SFP, and containment 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 0, guidance.

3.2 Reactor Core Cooling Strategies

Order EA-12-049 requires licensees to maintain or restore cooling to the reactor core in the event of an ELAP concurrent with a loss of normal access to the UHS. 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 with loss of normal access to the UHS) 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 residual heat, the RCS inventory should also 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 with loss of normal access to the UHS 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

The FIP states that in an ELAP event operators will enter existing Surry EOPs, which direct the operators to proceed with predetermined actions. A transition to Events and Condition Assessment (ECA)-0.0, “Loss of All AC Power,” is made upon determination of a total loss of ac power. Core cooling will be accomplished by natural circulation flow in the RCS using the SGs as the heat sink. The TDAFW pump initially takes suction from the ECST and then from the ECMT upon depletion of the ECST, and provides makeup water to the SGs, with the MSSVs and/or SG PORVs venting steam from the SGs. Operators will control the SG PORVs manually using the newly installed BDB SG PORV backup air supply located in the Main Steam Valve House (MSVH). The SG pressure is controlled above 300 psig by manipulating the SG PORVs, which provides sufficient steam pressure for operation of the TDAFW pump. The SG level is maintained high in the narrow range, to provide additional operational margin for recovery should the TDAFW pump degrade due to unanticipated conditions.

3.2.1.1.2 Phase 2

Upon depletion of the ECST and ECMT, the licensee will refill the ECST using the BDB High Capacity pump taking suction from the Condensate Polishing Settling Pond, discharge canal, or any number of non-robust water tanks, if available. The Phase 2 FLEX strategy for core cooling will supply feedwater to the SGs using the TDAFW pump as long as it is available. Additionally, portable diesel-driven BDB AFW pumps with both primary and alternate connections are available as a back-up to the TDAFW pumps. The BDB High Capacity pump will continue refilling the ECST or can provide water directly to the suction of the BDB AFW pump. The FIP indicates that the BDB AFW pump has a flow capacity of 300 gpm at 450 pounds per square inch differential (psid). As specified in Attachment 2 to the FIP, the BDB high capacity pump will be staged 10 hours into the event. Although there is no specific time during the event that requires BDB AFW pump to be placed in service, assuming the TDAFW pump continues to operate as expected, the BDB AFW pump will be staged as a backup to provide SG feedwater.

3.2.1.1.3 Phase 3

The Phase 3 core cooling strategy initially relies on Phase 2 strategies with the NSRC equipment providing backup equipment and the NSRC water processing equipment providing a purified water source. Once NSRC equipment arrives on site, the licensee can transition to Residual Heat Removal (RHR) and provide shutdown cooling as an alternate method of cooling the core.

3.2.1.2 RCS Makeup Strategy

3.2.1.2.1 Phase 1

Under ELAP conditions, RCS inventory will tend to diminish gradually due to leakage through RCP seals and other leakage points. Furthermore, the initial RCS cooldown starting at 2 hours into the event would result in a significant contraction of the RCS inventory, to the extent that the pressurizer would drain and a vapor void would form in the upper head of the reactor vessel.

Dominion determined that sufficient reactor coolant inventory would be available throughout Phase 1 to support heat transfer to the SGs via natural circulation without the need for active injection of RCS makeup. Procedure ECA-0.0 directs isolation of RCS letdown pathways and verification of RCS isolation. The RCS inventory loss is assumed to be through RCP seal leakage and operational leakage. Dominion has replaced all three Westinghouse-designed seals per unit with low-leakage Flowserve N-seals. Passive injection from the safety injection accumulators would occur as operators depressurize the RCS below the nitrogen cover gas pressure. This helps offset cooldown-induced inventory contraction and system leakage.

The licensee initiates a cooldown of the RCS within 2 hours of the initiation of the ELAP/LUHS event. The RCS is cooled down and depressurized until a SG pressure of 300 psig is reached. The minimum SG pressure of 300 psig is set to prevent nitrogen gas in the safety injection accumulators from being injected into the RCS. Cooldown and depressurization of the RCS significantly extends the expected coping time under ELAP/LUHS conditions because it (1) reduces the potential for damage to RCP seals (as discussed in Section 3.2.3.3) and (2) allows coolant stored in the nitrogen-pressurized accumulators to inject into the RCS to offset system leakage.

Dominion further indicated that, according to the core operating history specified in NEI 12-06, a sufficient concentration of xenon-135 should exist in the reactor core to ensure subcriticality throughout Phase 1, considering the planned cooldown profile. A cooldown to 300 psig in the SGs will correspond to an RCS core inlet temperature of approximately 422 °F. In addition to replenishing the RCS coolant volume, the passive injection from the nitrogen-pressurized safety injection accumulators would increase the boron concentration of the coolant in the RCS.

3.2.1.2.2 Phase 2

Per the FIP, RCS makeup is initiated within 16 hours of the ELAP/LUHS event. The RWST is the preferred source of borated makeup water. Makeup will be provided to the RCS using one of two 45-gpm BDB RCS injection pumps via primary or alternate connection points. Per the licensee's FIP, each BDB RCS injection pump is capable of injecting at pressures up to 2000 psig [pounds per square inch gauge].

The RWST is protected from all natural phenomena considered under Order EA-12-049 except for the high wind/tornado hazard. If the RWST is unavailable, the portable boric acid mixing tanks can be used to mix non-borated water with bags of powdered boric acid to provide a borated RCS makeup water source. To ensure consistency with its shutdown margin calculations, the licensee's procedures for batching borated coolant directs operators to target a mixture concentration greater than or equal to the minimum RWST concentration (i.e., approximately 2500 particles per million (ppm) boron or greater). As described in Table 3 of the licensee's FIP, additional fresh water sources for batching borated coolant should be available in analyzed ELAP scenarios where the RWST cannot be credited. However, if necessary, water from the Condensate Polishing Settling Pond could be used for mixing borated coolant. Water sources for mitigating the ELAP event are discussed further in Section 3.10 of this evaluation.

The BDB RCS injection pump will preferentially take suction from the two onsite RWSTs, if available. If both pumps are available and both RWSTs are available, one pump will be aligned to each RWST. The suction connection from the RWST is located on the Containment Spray pump suction elbow in each unit in the Containment Spray Pump House. These connections are protected from all applicable hazards except tornado missiles. If neither RWST is available, the pump(s) will be aligned to boric acid mixing tanks that will be available along with the necessary hoses and boric acid. The primary connection point for the BDB RCS injection pump is in the Safeguards Building downstream of the low head Safety Injection (LHSI) pump discharge MOVs, which inject into the RCS hot legs. The alternate connection is in the basement of the Auxiliary Building on the charging pump line and provides injection into the cold legs. These connection points are protected from all applicable hazards.

3.2.1.2.3 Phase 3

In Phase 3, the RCS makeup strategy is a continuation of the Phase 2 strategy, supplemented, as needed, with equipment provided by the NSRC. The NSRC will provide a high-pressure injection pump and mobile boration unit as backup for RCS makeup and boration requirements. As necessary, to facilitate the use of higher quality water for RCS makeup, the NRC staff expects that the licensee would begin using purification equipment from the NSRC as soon as practical considering the overall event response prioritization.

3.2.2 Variations to Core Cooling Strategy for Flooding Event

In its FIP, the licensee states that the James River has not resulted in flooding due to the wide flood plain at the site. The FIP also states that, during the most severe meteorological event at the Surry site, both Seismic Category I structures and the critical equipment for the FLEX strategies remain protected against flooding due to higher grade elevation. For those reasons, no variations to the cooling strategy are necessary. The site's flooding hazard evaluation is described in Section 3.5.2 of this safety evaluation (SE).

3.2.3 Staff Evaluations

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

Guidance document NEI 12-06 provides guidance 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.

3.2.3.1.1 Plant SSCs

Core Cooling – Phase 1

In FIP Section 2.3.4.1, the licensee states that each unit's TDAFW pump automatically starts and delivers AFW flow to all three SGs following an ELAP/LUHS event. The Updated Final Safety Analysis Report (UFSAR), Rev. 43, Table 15.2-1, indicates that the TDAFW pump is a Seismic Class I component located in a tornado-missile protected enclosure in the MSVH. In addition, UFSAR, Rev. 43, Section 10.3.5.1, indicates that all areas of the Auxiliary Feedwater System (i.e., pumps/motors, piping, valves/actuators, power supplies, instrumentation and control and structures having and supporting the system) are seismically qualified (Class I) to the design-basis earthquake level. Furthermore, UFSAR, Rev. 43, Section 2.3.1.2 states that the maximum flood height is 24' above mean sea level (MSL). As outlined in UFSAR, Rev. 43, Table 2.3-7, the MSVH is protected up to 26.5' MSL, so the TDAFW pump is protected from an external flooding hazard.

Two air-operated, normally closed pressure control valves (PCVs) supply steam to the TDAFW pump turbine. The PCVs are actuated when dc solenoids de-energize, venting air to open the valves and admit steam to the turbine. Therefore, loss of dc power does not isolate the TDAFW pump steam supply valves. If there is a loss of instrument air, the PCVs fail "as-is." However, the licensee states in FIP Section 2.3.4.1 that steam enters the PCVs from below the valve plug, thus the PCVs open with steam pressure. In the FIP, Section 2.3.4.1 states that, in the event the TDAFW pump fails to start, procedures direct the operators to manually reset and start the pump (which does not require electrical power for motive force or control). In the FIP, Section 2.3.4.1 further states that approximately 60 minutes are available to manually start the pump and initiate flow prior to steam generator dryout. Further explanation and the NRC staff's evaluation of the robustness and availability of water sources for an ELAP event is discussed in Section 3.10 of this SE. The staff finds that the TDAFW pumps are robust and are expected to be available at the start of an ELAP event, consistent with NEI 12-06, Section 3.2.1.3.

The licensee plans to vent steam from the SGs by manually controlling the SG PORVs and perform a controlled cooldown. As described in the Surry UFSAR, Rev. 43, Section 10.3.1.2, a steam generator PORV is located in each main steam safety valve header upstream of the main steam line trip valve. Furthermore, UFSAR, Rev. 43, Table 15.2-1 states that the main steam system, up to and including the main steam line trip valves, is Seismic Class I and is located in a tornado resistant structure. During the onsite audit the staff noted they PORVs are located in the MSVH. As stated above, the MSVH is also protected from a design-basis flood and is a Seismic Class I structure. The PORVs are controlled from an existing backup air bottle station located in the Containment Spray Pump House (CSPH), located adjacent to the MSVH. However, as noted in the FIP, the CSPH is not fully tornado missile protected. Therefore, a new backup air bottle system for manually controlling the PORVs was installed on the ground floor of the MSVH, which is fully protected from all applicable hazards. As stated in Design Change document SU-13-01168, "BDB FLEX Strategy Support Modifications," Rev. 0, the SG PORV backup air bottle system is seismically qualified. While onsite, licensee provided calculation ME-12133, "Evaluation of the Surry Back-up Air Bottle (Compressed Air) Supply to MS S/G PORVs Located in MSVH (BDB) and CSPH," Rev. 0. This calculation analyzed the number of cycles and time limit for the backup air bottle system. The calculation showed that a bottle would last 40 cycles over a 6 hour time period and would last approximately 12 hours if the PORV was opened once, and held open with minor adjustments while performing a plant cooldown. The NRC staff finds that the SG PORVs and manual backup air bottle station are robust and are expected to be available at the start of an ELAP event consistent with NEI 12-06, Section 3.2.1.3.

Core Cooling – Phase 2

The licensee's Phase 2 core cooling strategy continues to use the SGs as the heat sink. The licensee will continue to use the TDAFW pump as long as possible, or transition to a portable BDB AFW pump discharging through a primary or alternate connection point to the SGs that does not rely on any installed plant SSCs other than installed systems with FLEX connection points and water sources discussed in SE Sections 3.7 and 3.10, respectively.

Core Cooling – Phase 3.

The Phase 3 core cooling performs the same function as the Phase 2 equipment, for which it provides a backup. Phase 3 equipment can also support the use of a RHR to provide an alternate method of core cooling. To use RHR, the licensee needs to use equipment in the CC, SW, and RHR systems. In the UFSAR, Table 15.2-1, Rev. 43, indicates that the CC, SW, and RHR pumps and systems are Seismic Class I components and are located in structures that provide tornado protection. The NRC staff noted that these systems are located in the Containment and Auxiliary buildings, which are flood protected to a height of 26.5 feet above MSL per UFSAR, Rev. 43, Table 2.3-7. This level is below the maximum flood height of 24' above MSL; thus those components are protected from an external flood. The NRC staff finds these systems are robust and should be available during an ELAP event consistent with NEI 12-06, Section 3.2.1.3.

RCS Inventory Control – Phase 1

The licensee's Phase 1 RCS inventory control FLEX strategy relies on Flowserve N-9000 seals, and the licensee's analyses demonstrated that no FLEX RCS make up is needed within 16 hours.

RCS Inventory Control – Phase 2

The licensee's Phase 2 RCS inventory strategy will use a diesel driven FLEX RCS Injection pump with FLEX connection points and borated water sources discussed in Sections 3.7 and 3.10 respectively.

RCS Inventory Control – Phase 3

The licensee Phase 3 RCS inventory strategy does not rely on any additional installed plant SSCs other than those discussed in Phase 2. However, the licensee can establish shutdown cooling as described in the Core Cooling – Phase 3 Section above.

3.2.3.1.2 <u>Plant Instrumentation</u>

According to the licensee's FIP, the following key parameters are credited and available, as described below, for all phases of reactor core cooling and decay heat removal strategy.

- FW Flowrate – AFW flowrate indication is available in the Main Control Room. However, following load stripping only B SG flow is available throughout the event.
- SG Water Level – Narrow range (NR) level indication is available in the MCR for all SGs throughout the event. SG A wide range level would also be available throughout the event in the MCR.
- SG Pressure – SG pressure indication is available in the MCR and at the remote monitoring panel (RMP) (for two channels). SG pressure indication is available for all SGs throughout the event.
- RCS Temperature – RCS hot-leg and cold-leg temperature indications are available in the MCR for all loops until load stripping. After load stripping only B RCS loop will be available. The licensee's plan is to remain in symmetric natural circulation. Therefore, the B loop RCS temperature should be representative of all three loops. Also, since the plant is in natural circulation, SG pressure indication would allow for RCS temperature calculation through relation to saturation temperatures.
- RCS Pressure – RCS wide range pressure indication is available in the MCR and at the RMP throughout the event.
- Core Exit Thermocouple Temperature – Core exit thermocouple temperature indications are available throughout the event in the MCR.
- ECST Level – ECST water level indication is available in the MCR until load stripping. After load stripping it is available locally at the tank throughout the event.
- Pressurizer level - Pressurizer level indication is available in the MCR throughout the event.
- Reactor Vessel Level Monitoring System (RVLMS) - RVLMS indication is available from the MCR throughout the event.
- Excore Nuclear Instruments – Indication of nuclear source range activity is available in the MCR and RMP throughout the event.

The instrumentation available to support the licensee's strategies for core cooling and RCS inventory during the ELAP event is generally consistent with and in some cases exceeds the recommendations specified in the endorsed guidance of NEI 12-06. As a result, the NRC staff considered the intent of the endorsed guidance from NEI 12-06 to be satisfied.

All FLEX portable equipment is equipped with the necessary local instrumentation to operate the equipment, and operation is detailed in the FLEX support guidelines (FSGs).

FSG-7, "Loss of Vital Instrumentation or Control Power," includes instructions for obtaining critical parameters locally in the unlikely event that all ac and dc power is lost.

3.2.3.2 Thermal-Hydraulic Analyses

Dominion concluded that its mitigating strategy for reactor core cooling at Surry would be adequate, based in part, on generic thermal-hydraulic analysis performed for a reference Westinghouse four-loop reactor 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. In the Pressurized-Water Reactor Owners Group (PWROG) Core Cooling Position Paper, which was provided in a letter dated January 30, 2013, the PWROG recommended that the reflux or boiler-condenser cooling phase be avoided because of uncertainties in operators' ability to control natural circulation following reflux boiling and the impact of the diluted pockets of water on criticality. Due to the challenge of resolving the above issues within the compliance schedule specified in Order EA-12-049, the NRC staff requested that PWR licensees 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 the PWROG-sponsored Technical 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," and WCAP-17792-P, "Emergency Procedure Development Strategies for the Extended Loss of AC Power Event for all Domestic Pressurized Water Reactor 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 is 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. Further discussion of the staff's review, including conditions and limitations regarding the application of the NOTRUMP code to analysis of the ELAP event, may be found in the NRC staff's endorsement letter on this subject, dated June 16, 2015 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML 15061A442).

Although the NRC staff obtained confidence that the NOTRUMP code is capable of performing best-estimate ELAP simulations prior to the initiation of reflux cooling using the one-tenth flow quality criterion discussed above, the staff was unable to conclude that the generic analysis performed in WCAP-17601-P could be directly applied to all Westinghouse PWRs, as the vendor originally intended. In PWROG-14064-P, Rev. 0, the industry subsequently recognized that the generic analysis would need to be scaled to account for plant-specific variation in RCP seal leakage. However, the staff's review, supported by sensitivity analysis performed with the TRACE code, further identified that plant-to-plant variation in additional parameters, such as RCS cooldown terminus, accumulator pressure and liquid fraction, and initial RCS mass, could also result in substantial differences between the generically predicted reference coping time and the actual coping times that would exist for specific plants.

Dominion performed a site-specific applicability review of the generic analysis in Section 5.2.1 of WCAP-17601 and found the overall results to be bounded by the model and inputs used in WCAP-17601 and associated analytical codes. During the audit, the NRC staff confirmed the similarity of the parameters in the reference analysis from WCAP-17601-P to the applicable values for Surry, Unit Nos. 1 and 2.

However, the leakage rate boundary condition assumed in the generic Westinghouse thermal-hydraulic analysis differs from the plant-specific condition for Surry. Whereas the generic Westinghouse three-loop analysis assumed an RCS leakage rate commensurate with three Westinghouse-designed RCP seals, all three seals in each Surry unit have been replaced by Flowserve N-9000 seals, which would have a lower leakage rate. Therefore, the NRC staff's SE considers the plant configuration with Flowserve N-9000 seals installed on all three RCPs.

Based on information from WCAP-17601-P and PWROG-14027-P, reflux cooling was estimated to occur before 30 hours for the Westinghouse three-loop reference case with the T_{hot} upper head configuration, assuming leakage rates for standard Westinghouse-designed RCP seals. The licensee subsequently performed an additional scaling analysis to consider its existing plant-specific RCP seal configuration with Flowserve N seals. The results showed times in excess of 30 hours for loss of natural circulation. Per its FLEX strategy, Surry will begin RCS inventory makeup well before 30 hours of the onset of the ELAP condition, which the NRC staff concludes should provide ample margin to the time where reflux cooling is expected for the analyzed ELAP event considering the configuration with four Flowserve N-9000 seals installed.

The NRC staff's audit review found the licensee's thermal-hydraulic analysis to be in adequate conformance with applicable guidance documents (e.g., NEI 12-06, the NRC staff's endorsement letter regarding the NOTRUMP code, WCAP-17601-P, PWROG-14207-P). Therefore, based on the evaluation above, the licensee's analytical approach should appropriately determine the sequence of events, including time-sensitive operator actions, and 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, potentially resulting in increased 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 imbalances in boric acid concentration. Along with cooldown-induced shrinkage 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.

Surry, Unit Nos. 1 and 2, are three-loop Westinghouse PWRs with one Westinghouse RCP in each loop. The RCPs at Surry originally used standard three-stage Westinghouse seal packages. Surry has since replaced all of the Westinghouse-designed RCP seals with low-leakage Flowserve N-9000 seals with the Abeyance feature.

The N-9000 seal is a product in Flowserve's N-seal line of hydrodynamic seals that was developed in the 1980s. One of the design objectives for the N-seal was to provide low-leakage performance under loss-of-seal-cooling conditions during events such as a station blackout. In support of its customers' efforts to address the ELAP event (which similarly involves a loss of seal cooling) in accordance with Order EA-12-049, on August 3, 2015, Flowserve submitted to the NRC staff its "White Paper on the Response of the N-Seal Reactor Coolant Pump (RCP) Seal Package to Extended Loss of All Power (ELAP)," (ADAMS Accession No. ML15222A366). The N-Seal white paper contains information regarding the expected leakage rates over the course of an ELAP event for each PWR at which Flowserve N-Seals are currently installed. By letter dated November 12, 2015 (ADAMS Accession No. ML15310A094), the staff endorsed the leakage rates described in the white paper for the beyond-design-basis ELAP event, subject to certain limitations and conditions.

The plant-specific calculations performed by Flowserve in its white paper indicate that a seal leakoff flow of 2.5 gpm per pump is applicable for Surry during the initial phases of the ELAP event. Considering all 3 RCPs and accounting for another 1 gpm of additional RCS leakage implies a total RCS leakage of 8.5 gpm during this time. However, these calculations presume that the leakage rate would increase after approximately 100 hours into the event when the Surry FLEX scenario exceeds the elastomer thermal design margin demonstrated in a station blackout test conducted by Flowserve in 1988. Specifically, according to Flowserve's calculations, the leakage would increase from 2.5 gpm per pump to 4.2 gpm per pump at this time, which would result in the total RCS leakage rate increasing from 8.5 gpm to approximately 14 gpm.

During the audit, the NRC staff considered the status of the licensee's conformance with the Flowserve N-Seal white paper and the limitations and conditions in the NRC staff's endorsement letter. In particular, as noted in the Flowserve white paper, the licensee confirmed that the plant design and planned mitigation strategy of Surry are consistent with the information assumed in the calculation performed by Flowserve, as summarized in Table 1 of the white paper. The NRC staff's audit of the applicable information from the Flowserve white paper against the strategy in the licensee's FIP further verified consistency. Additionally, the peak cold-leg temperature prior to the RCS cooldown assumed in Flowserve's analysis was found to be equivalent to the saturation temperature corresponding to the lowest setpoint for SG safety valve lift pressure in the Surry UFSAR. Based upon its audit review, the NRC staff further considered the intent of the endorsement letter's condition on the density of the coolant leaking from the RCS to be satisfied inasmuch as ample margin is available between the time that the licensee's mitigating strategy would supply RCS makeup and the time at which entry to reflux cooling would be expected to occur for the analyzed ELAP event.

Therefore, 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.

3.2.3.4 Shutdown Margin Analyses

In an assumed 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 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.

The NRC staff 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 conditions intended to ensure that boric acid addition and mixing during an ELAP event 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:

- The required timing and quantity of borated makeup should consider conditions with no RCS leakage and with the highest applicable leakage rate.
- 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.
- 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 one hour is considered appropriate.

During the audit review, Dominion confirmed that Surry will comply with the August 15, 2013, position paper on boric acid mixing, including the conditions imposed in the staff's corresponding endorsement letter. The NRC staff's audit review concluded that these conditions should be satisified since (1) the licensee's analyses considered the appropriate range of RCS leakage conditions, (2) the licensee would initiate FLEX RCS makeup prior to RCS flow decreasing below the single-phase natural circulation flow rate, and (3) the licensee's plan for initiating RCS makeup would allow a one-hour delay period for boric acid mixing.

During the audit, the NRC staff reviewed the licensee's shutdown margin calculation. The licensee's analysis determined that the injection of borated coolant is required by 25 hours into the event to ensure that recriticality can be avoided as the core xenon concentration decays away. According to the FIP, borated water will be injected into the RCS no later than 16 hours into the event. The licensee calculated that approximately 2400 gallons of 2600 ppm borated water from the RWST would be adequate to meet 1 percent shutdown margin requirements for RCS conditions commensurate with an SG pressure of 300 psig (approximately 425°F cold leg temperature). Although the RWST is not fully robust, the shutdown margin calculation considered this source of borated coolant as bounding other potential sources. The NRC staff considered this assessment reasonable because the boron concentration of other sources used for active FLEX injection is expected to be greater than or equal to this value. Plant operators would be procedurally directed to mix to a concentration of greater than 2500 ppm boron using the portable batching tanks. The licensee's calculations do not credit the boron that may be injected passively from the safety injection accumulators.

Per FSG-8, "Alternate RCS Boration," injection of a total of 2400 gallons of RWST water would be necessary to ensure adequate shutdown margin at the limiting end-of-cycle condition at a core inlet temperature of 350 °F. If the RWST is not available, 2400 gallons of boric acid solution at a similar concentration would be injected from the portable boric acid mixing tanks. Surry will perform checks every core reload to determine that any core design changes do not adversely impact the approved FLEX strategies, especially the analyses which demonstrate that no recriticality will occur during a FLEX RCS cooldown.

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 in analyzed cases where minimal RCS leakage occurs. The licensee stated that its calculations indicated that the volume of borated coolant necessary for adequate shutdown margin could be accommodated by the RCS free volume available following the inventory contraction associated with the planned RCS cooldown. As such, the licensee expected that its high-pressure BDB RCS injection pump could inject the necessary coolant volume under ELAP conditions without the need for venting the RCS. The NRC staff reviewed these calculations and noted that, although not considered in the licensee's calculations, accumulator injection during the actual event may refill a significant portion of the available RCS free volume. However, due in part to the lack of available instrumentation during the event, quantifying and relying upon the boron passively injected by the accumulators may not be a viable option for plant operators. Therefore, in addition to being desirable from the standpoint of limiting the potential for RCS pressure increases during FLEX injection, RCS venting may effectively become a practical necessity in an actual event due to the limited information available to plant operators. During the audit, the licensee indicated that the reactor vessel head vent lines, as well as the pressurizer vent lines, contain dc-powered valves that would be reenergized via FSG-8, if necessary, and opened remotely from the main control room under ELAP conditions to support the addition of borated coolant to ensure adequate reactor shutdown margin.

For long-term boron needs, Surry could continue batching borated coolant using their portable mixing tanks. They are also receiving water purification and boration skids from the NSRC.

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

The licensee's FLEX strategy relies on three different portable pumps during Phase 2. In the FIP, Section 2.3.10 identifies the performance criteria (e.g., flow rate, discharge pressure) for its BDB Phase 2 portable pumps. The NRC staff noted that the performance criteria for the FLEX Phase 2 portable pumps are consistent with the FLEX Phase 3 portable pumps capacities. See Section 3.10 for discussion of the availability and robustness of each water source.

BDB High Capacity Pump

The licensee relies on a BDB high capacity pump to provide water for long-term AFW, SFP and possibly RCS makeup. A BDB High Capacity Pump that supplies water to the BDB AFW pump, portable boration mixing tanks and directly to the SFP, and it takes suction from either the Settling Pond or the Circulating Water Discharge Canal. The licensee procured a trailer-mounted, diesel-driven centrifugal pump stored in the BDB Storage Building. One BDB high capacity pump is required for both units so the licensee has two pumps to satisfy the N+1 requirement while the other pump is available to meet the requirements of 50.54(hh)(2). Although the licensee has two high capacity pumps, the licensee's FLEX strategy providing makeup water is an alternative to NEI 12-06 because the 50.54(hh)(2) pump is stored in the Emergency Response Building, which is not protected from all applicable hazards. For more discussion on this alternative to NEI 12-06 guidance, see SE Section 3.14.1. In the FIP, Section 2.3.10.1 states that either BDB high capacity pump can provide 1200 gpm (300 gpm for each unit's SG and 500 gpm for the SFP) at 150 psid. During the audit, the licensee provided calculation ME-0967, "Beyond Design Basis (BDB) – BDB High Capacity Pump and BDB AFW Pump Hydraulic Analysis for Spent Fuel Pool Makeup and AFW Injection at Surry Unit Nos. 1 and 2," Rev. 0. The purpose of this calculation was to validate the flow qualification (discharge pressure, flow and net positive suction head (NPSH) of the BDB high capacity and BDB AFW pump using Fathom Version 7.0 modeling computer software. The hydraulic model takes into account both suctions sources, the discharge canal and settling pond, and uses pump flow data from both high capacity pumps.

Core Cooling – BDB AFW Pump

During Phase 2 or Phase 3, core cooling may be accomplished by a portable diesel-driven SG makeup pump when the TDAFW pump is no longer available. The BDB AFW pump will take suction from the ECST, which is refilled using the BDB high capacity pump, or the BDB AFW pump can take suction directly from the discharge of the BDB high capacity pump. The BDB AFW pump is a portable diesel-driven centrifugal pump. A single pump provides full capability to feed all three generators in one unit, so Surry has three portable FLEX AFW Pumps to satisfy the N+1 requirement outlined in NEI 12-06. All three BDB AFW pumps are stored in the BDB Storage Building. In the FIP, Section 2.3.10.2 states that the BDB AFW pump can provide 300 gpm at 450 psid. As noted above, the licensee performed calculation ME-0967 to determine the fluid system hydraulic performance, and to validate that the BDB AFW pumps have adequate performance characteristics. The NRC staff noted that this calculation assessed different possible lineups based on such variables as suction sources, connection points and hose paths to determine the flow to ensure that the BDB AFW pump procured by the licensee is adequate for providing injection into the SGs at the required flow rate and discharge pressure.

RCS Inventory Control – RCS Makeup Pump

Makeup is provided to the RCS with a portable diesel-driven BDB RCS Injection pump with its suction from the RWST or a portable boron mixing tank to compensate for RCS volume contraction during cool-down and RCS leakage such as RCP seal leakage. In the FIP, Section 2.3.10.3 indicates that the BDB RCS Injection pump can provide a minimum flow of 45 gpm at discharge pressure greater than 2000 psig. Additionally, one pump can provide makeup to both units so the licensee procured two to meet the N+1 requirement of NEI 12-06. The BDB RCS Injection pump and the portable boron mixing tank are stored in the BDB Storage Building.

During the audit, the licensee provided ME-0964, “Evaluate the High Head Injection pump for Beyond Design Basis (BDB) at the primary and alternative supply locations in Modes 1-4, and the BDB AFW Pump in Modes 5 and 6,” Rev. 0, which used the computer software Pipe2010, Rev. 5.010 vr6, to analyze the pump performance criteria. This calculation analyzed different possible lineups based on different suction sources, connection points and hose paths to ensure that the FLEX RCS make-up pump procured by the licensee is adequate for providing injection into the RCS at the required flow rate and discharge pressure.

During the audit, the NRC staff performed a walkdown of the licensee’s core cooling FLEX strategies and noted the staging locations for all three portable BDB pumps, hose routing and deployment connection points (primary and alternate) were consistent with the licensee’s hydraulic analyses.

Based on its review, the NRC staff concludes that the licensee has demonstrated that its BDB portable pumps are capable of supporting the licensee’s FLEX strategies if implementation is performed as described in the FIP.

3.2.3.6 Electrical Analyses

The licensee's FIP defined strategies capable of mitigating a simultaneous ELAP/LUHS resulting from a BDBEE by providing the capability to maintain or restore core cooling at Surry Units 1 and 2. The licensee's strategy for RCS inventory control uses the same electrical strategy as for maintaining or 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 to determine whether the FLEX strategies, if implemented appropriately, should maintain or restore core cooling, containment, and spent fuel pool cooling following a BDBEE. As part of its review, the NRC staff reviewed 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 losing heating, ventilation, and air conditioning (HVAC) during an ELAP/LUHS as a result of a BDBEE. The NRC staff also reviewed the separation and isolation of the FLEX generators from the Class 1E emergency diesel generators (EDGs) and procedures that direct operators how to align, connect, and protect associated systems and components.

According to the licensee's FIP, operators respond to the ELAP/LUHS event in accordance with EOPs to confirm RCS, secondary system, and containment conditions. A transition 1(2) ECA-0.0 is made upon the diagnosis of the total loss of ac power. This procedure (along with referenced FSGs) directs isolation of RCS letdown pathways, verification of containment isolation, reduction of dc loads on the station Class 1E batteries, and establishment of electrical equipment alignment in preparation for eventual power restoration.

The Surry Phase 1 FLEX mitigating strategy involves relying on installed plant equipment and onsite resources, such as use of 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 station batteries will be needed in an ELAP to power loads such as shutdown system instrumentation, control systems, and re-powered AOVs and MOVs. 1(2)-FSG-4, "ELAP DC Bus Load Shed/Management," Rev. 0(1), directs operators to conserve dc power during the event by stripping, or load shedding, nonessential dc loads. The plant operators would commence load shedding nonessential dc loads within 45 minutes after the occurrence of an ELAP/LUHS event. The licensee expects load shedding to be completed within 30 minutes.

The Surry, Unit Nos. 1 and 2, vital batteries contain 60 cells each and were manufactured by Enersys (model GN-23) with a capacity of 1800 ampere-hours. The licensee noted and the NRC staff confirmed that the useable station battery capacity could be extended up to 14 hours by load shedding non-essential loads.

In its FIP, the licensee noted that it 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 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 licensee’s Phase 1 mitigation strategy includes cross-tying each Surry Unit’s two Class 1E batteries and four Class 1E Battery Chargers. The licensee performed a dc bus cross-tie study that concluded that dc protective devices with sufficient ratings were available when the dc bus is cross-tied.

During the onsite portion of the audit, the NRC staff reviewed the summary of the licensee's dc system analysis (Addendum D to EE-0046, “Surry 125V DC Loading Analysis,” Rev. 2) to verify the capability of the dc system to supply the required loads during the first phase of the Surry FLEX mitigation strategies plan. The licensee’s evaluation identified the required loads and their associated ratings (ampere (A) and minimum required voltage) and the loads that would be shed within 75 minutes to ensure battery operation for least 14 hours. This provides ample margin to transition to Phase 2 as the licensee expects Phase 2 equipment to be deployed within 8 hours of the onset of an ELAP as a result of a BDBEE.

Based on the staff's review of the licensee's analysis, the battery vendor's capacity and discharge rates for the batteries, and the licensee’s procedures, the NRC staff finds that the Surry, Units 1 and 2, dc systems have adequate capacity and capability to power the loads required to mitigate the consequences during Phase 1 of an ELAP as a result of a BDBEE provided that necessary load shedding is completed within the times assumed in the licensee's analysis.

The licensee’s Phase 2 strategy includes re-powering vital 120 Vac buses within 14 hours using a portable 350-kilowatt (kW)/437.5 Kilovolt Ampere (kVA) 480 Vac FLEX DG (one per unit) stored in the robust BDB Storage Building located onsite. The licensee’s transition to Phase 2 is expected to occur much earlier than the calculated depletion of the Class 1E 125 V dc batteries (within 8 hours versus a calculated battery capacity of 14 hours). The portable 480 Vac FLEX DGs would supply power to Surry, Unit Nos. 1 and 2 vital 120 Vac circuits providing continuity of key parameter monitoring and other required loads. A portable 40 kW/46.64 kVA (standby rating) 120/240 Vac FLEX DG (3 available but only 1 is needed per unit) is available as an alternate to the 480 Vac DGs. For the 480 Vac FLEX DG, the licensee's FLEX DG sizing calculation EE-0864, "Surry Power Station Beyond Design Basis – FLEX Electrical 480VAC and 120VAC System Loading Analysis," Rev. 2, identified the required loads to be 179.58 kVA (approximately 143.66 kW at .8 power factor) during the first day of the event and then 156.13 kVA (approximately 124.90 kW at .8 power factor) per unit from day 2 of the event and beyond. The same calculation identified the required loads for the 120 Vac FLEX DG as 30.7 kVA (24.56 kW at .8 power factor). The licensee's calculation also addressed breaker coordination and the minimum required voltage for these DGs.

The licensee's primary FLEX strategy for re-powering 120 Vac vital bus circuits is through the use of pre-installed connections and the deployment of one 480 Vac FLEX DG per unit connected to the Class 1E 480 Vac bus. The 480 Vac FLEX DG energizes battery chargers which allows for recharging the Class 1E batteries and restoring other ac loads in addition to key parameter monitoring instrumentation. Operators would deploy the portable 480 Vac DGs and their associated cables from the BDB Storage Building to the alleyways on the west and east sides of the Auxiliary Building. The power cables would be connected to seismically-designed, tornado-missile protected, connection receptacles in each unit's upper cable vault. The connection receptacles in the upper cable vaults are connected to the Class 1E 480 Vac bus via pre-installed cable and conduit to Class 1E 480 Vac motor control center (MCC) breakers. 1(2)-FSG 4, provides direction for ensuring proper phase rotation before attempting to power equipment from the 480 Vac FLEX DGs.

The licensee's alternate strategy for re-powering 120 Vac vital bus circuits is to use one 120/240 Vac DG per unit connected to the 120 Vac vital buses through pre-installed BDB receptacle panels, cabling, connections, and distribution panels. The portable 120/240 Vac DGs are stored in the BDB Storage Building and would be deployed to the alleyways east of the Auxiliary Building for Unit 1 and west of the Auxiliary Building for Unit 2. The DGs would be connected via cables to receptacle panels located in the Upper Cable Vault of each unit. The 120/240 Vac cables for each unit are stored on two 100' cable reels located in each unit's Upper Cable Vault. Backup cables would be transported from the BDB Storage Building on the same cable trailer as the 480 Vac cables for that unit. Each 120/240 Vac DG has two output circuits that supply two BDB distribution panels which provide power to the vital 120 Vac buses and selected lighting circuits for that unit. The BDB receptacle in each unit's Upper Cable Vault is connected to the BDB distribution panels via pre-installed cable and conduit.

If not utilized as the alternate power source for key instrumentation, the 120/240 Vac DGs could be used to supply lighting and act as one of the available sources to power the portable fans used to disperse hydrogen from the battery rooms when the 480 Vac generators are charging the batteries via the inverters.

Based on its review of the summary of the licensee's calculation, conceptual single line electrical diagrams, and station procedures, the NRC staff finds that the licensee's approach is acceptable given the protection and diversity of the power supply pathways, the separation and isolation of the FLEX DGs from the Class 1E EDGs, and availability of procedures to direct operators how to align, connect, and protect associated systems and components. The NRC staff also finds that the FLEX DGs have sufficient capacity and capability to supply the required loads.

For Phase 3, the licensee 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 includes two 1-megawatt (MW) 4160 Vac combustion turbine generators, a distribution panel (including cables and connectors), and an 1100 kW 480 Vac combustion turbine generator per unit.

The two 1-MW 4160 Vac combustion turbine generators would be connected to the distribution panel in order to meet the required 4160 Vac load requirements for each unit. Due to the size of the equipment, the turbine generators would be deployed to the area by the large opening in the Unit 2 Turbine Building Truck bay on the outside of the EDG rooms. The Emergency Switchgear Room would be used to tie the 4160 Vac combustion turbine generators to one of the two Class 1E 4160 Vac buses for each unit. 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. Necessary cable for any of the above connections are also provided from the NSRC.

Each portable 4160 Vac combustion turbine generator is capable of supplying approximately 1-MW, but two combustion turbine generators will be operated in parallel to provide approximately 2 MW (2.5 MVA at .8 power factor). Per calculation EE-0872, "Calculations for Surry Power Station Beyond Design Basis – FLEX Electrical 4160VAC System Loading Analysis," Rev. 0, the total loads for Phase 3 equals 1.3 MW. 1(2)-FSG 15, "4160 VAC Generator Connection and Operation," Rev. 0, provides direction for ensuring proper phase rotation before attempting to power equipment from the 4160 Vac combustion turbine generators. The 480 Vac combustion turbine generator has a capacity of 1100 kW and would serve as a backup to the Phase 2 480 Vac FLEX DG. Based on its review, the NRC staff finds that the 4160 Vac and 480 Vac equipment being supplied from the NSRCs has sufficient capacity and capability to supply the required loads.

3.2.4 Conclusions

Based on this evaluation, the NRC staff concludes that the licensee has developed guidance that appears to maintain or restore core cooling during an ELAP/LUHS event consistent with NEI 12-06 guidance, as endorsed, by JLD-ISG-2012-01 (with the alternatives described in Section 3.14), and should adequately address the requirements of the order.

3.3 Spent Fuel Pool Cooling Strategies

NEI 12-06, Table 3-2 and Appendix D, provide guidance for 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 gallons per minute (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. 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.

In 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.

3.3.1 Phase 1

In the FIP, Section 2.4.1 indicates that the licensee's evaluations estimate that, with no operator action, following a loss of SFP cooling at the maximum design heat load, the SFP will reach 212°F in approximately 12 hours and boil off to a level 10 feet above the top of fuel in 51 hours from initiation of the event. The Phase 1 coping strategy for SFP cooling is to monitor SFP level using instrumentation installed as required by NRC Order EA-12-051. In addition, the licensee will establish a ventilation path whereby natural circulation will remove steam from the SFP area in order to inhibit the formation and buildup of condensation.

3.3.2 Phase 2

The licensee's Phase 2 SFP cooling strategy consists of deploying the BDB High Capacity pump to provide makeup from the CP Settling Pond or discharge canal. In the FIP, Section 2.4.2 states that hoses from the BDB High Capacity pump discharge can be routed to an external connection to the SFP cooling system (not requiring refueling floor access), to the FP system, which feeds the emergency SFP makeup line, or routed to the refuel floor to provide direct makeup to the pool and/or spray flow. The BDB High Capacity pump is capable of providing up to 500 gpm of spray flow to the SFP.

3.3.3 Phase 3

The license indicated that the strategies described for Phase 2 SFP cooling can continue as long as there is sufficient inventory available. In the FIP, Section 2.4.3 states that additional low pressure/high flow pumps will be available from the NSRC as a backup to the onsite BDB High Capacity pumps.

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.

In the FIP, Section 2.4.1 states that the Phase 1 SFP cooling strategy does not require any anticipated actions. However, the licensee does establish a ventilation path to cope with temperature, humidity and condensation from evaporation and/or boiling of the SFP early in the ELAP event. The BDB FSG implements a method of ventilation for the Fuel Handling Building. Specifically, Attachment 8 of 0-FSG-5, "Initial Assessment and FLEX Equipment Staging," Rev. 1, directs operators to open four large roll-up doors to minimize steam build-up and condensation in the Fuel Handling Building. Although the procedure does not direct opening of these doors within a specific time constraint, during the audit the licensee provided calculation MISC-11792, "Extended Loss of AC Power, Spent Fuel Pool Heatup Times and Makeup Water for Dominion Nuclear Units," Rev. 0, which conservatively concluded that the SFP would not begin to boil for at least 12 hours following an ELAP-initiating event during a worst case maximum heat load situation. Furthermore, the calculation concluded that the level in the SFP would not be less than 10 feet above the fuel racks for 51 hours following an ELAP-initiating event. Table 4 in the licensee's FIP states the BDB High Capacity pump will be deployed and able to provide makeup within 10 hours of the event. The staff noted that 0-FSG-11, "Alternate SFP Makeup and Cooling," directs operators to record the latest up-to-date SFP time to 200°F and contains precautions that steam from the SFP can condense and damage equipment. Additionally, the licensee's preferred methods (both primary using external connection and alternate using the FP system) do not require access to the Fuel Handling Building. Based on the administrative controls to establish ventilation in the Fuel Handling Building before bulk boiling occurs, the relatively long time before the SFP level would approach the top of the fuel racks, and the higher prioritization of the strategies that do not require entry into the SFP area, the proposed ventilation strategy is sufficient to facilitate the maintenance of SFP cooling following a BDB event.

The licensee's Phase 2 and Phase 3 SFP cooling strategy involves use of the BDB High Capacity pump using the settling pond or discharge canal as a suction source. The staff's evaluation of the robustness and availability of FLEX connections points for the FLEX pump is discussed in SE Section 3.7.3.1. Furthermore, the staff's evaluation of the robustness and availability of water sources for an ELAP event is discussed in SE Section 3.10.

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 calculation MISC-11792, the licensee analyzed the worst case, maximum SFP cooling heat load case when determining SFP makeup rate. The maximum heat load, boil-off time to top of the fuel and makeup rate can be found in the table below.

	Heat Load	Time to boil to 15 ft from top of fuel	Makeup rate
Worst Case Heat Load	40.8 million Btu/hr	51 hrs	78 gpm

As stated in SE Section 3.2.3.5, the licensee's FLEX Pump is capable of supplying up to 500 gpm of SFP spray flow, which is more than the worst case SFP makeup requirements.

The staff noted that NEI 12-06, Section 3.2.1.6, states that one of the initial SFP conditions is that the SFP heat load assumes the maximum design-basis heat load for the site. Consistent with NEI 12-06, Section 3.2.1.6, the staff finds that the licensee has considered the maximum design-basis SFP heat load and has demonstrated that the FLEX Pump is capable to provide the 78 gpm makeup rate.

3.3.4.3 FLEX Pumps and Water Supplies

As described in the FIP, the SFP cooling strategy relies on the BDB High Capacity pump to provide SFP makeup during Phase 2. In the FIP, Section 2.3.10.1 describes the hydraulic performance criteria (e.g., flow rate, discharge pressure) for the BDB High Capacity pump. The staff noted that the performance criteria of a FLEX pump supplied from an NSRC for Phase 3 would allow the NSRC pump to fulfill the mission of the onsite FLEX pump if the onsite FLEX pump were to fail. As stated above, the SFP spray rate of 500 gpm both meet or exceed the maximum SFP makeup requirements as outlined in the previous section of this SE. The staff's review of the capability for the BDB High Capacity Pump is discussed in SE Section 3.2.3.5.

3.3.4.4 Electrical Analyses

The licensee's FIP defines strategies capable of mitigating a simultaneous ELAP and LUHS, resulting from a BDBEE, by providing the capability to maintain or restore core cooling, containment, and SFP cooling at all units on the Surry site.

The staff performed a comprehensive analysis of the licensee's electrical strategies, which includes the SFP cooling strategy. The only 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), is the ability to use the onsite portable FLEX DGs within 72 hours as an alternative source for providing power to the instrumentation and display panels and to recharge the backup battery for the instrumentation required by Order EA-12-051, if necessary. The staff reviewed the licensee's FLEX DG sizing calculation EE-0864, and determined that the FLEX DGs have sufficient capacity and capability to supply these loads, 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 an ELAP consistent with NEI 12-06 guidance, 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 subatmospheric containment.

The licensee performed a containment evaluation, calculation MISC-11793, "Evaluation of Long Term Containment Pressure and Temperature Profiles Following Extended Loss of AC (ELAP)," Revision 0, based on the boundary conditions described in Section 2 of NEI 12-06. The calculation, which analyzed the strategy of containment isolation and monitoring containment parameters, concluded that the containment parameter of pressure remains well below the respective UFSAR Section 5.4 design limit of 45 psig for more than 7 days. 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 strategy involves verifying Containment Isolation and monitoring Containment pressure and temperature using installed instrumentation. Containment isolation is verified per ECA-0.0. Containment wide range pressure is available in the Control Room for the duration of the event. Containment temperature is available in the Control Room prior to dc load stripping and following repowering the dc loads with either the 480 volt ac or 120/240 portable diesel generators.

3.4.2 Phase 2

Phase 2 coping strategy is to continue monitoring containment pressure and temperature using installed instrumentation. Containment pressure and temperature will be monitored from the Control Room following repowering of dc loads through Phase 2 activities.

3.4.3 Phase 3

The Phase 3 strategy for reducing containment temperature is to utilize existing plant equipment supplemented by FLEX equipment or equipment furnished by NSRC. There are several options for Phase 3 coping, using the existing CARF cooling or using containment spray. Either of the Class 1E 4160 Vac buses will be repowered using a NSCR electric generator. This will permit repowering the Class 1E 480 Vac buses. Repowering the electrical buses is described in Section 2.3.3 of the FIP. If the service water pumps are not available, diesel driven pumps from NSCR can be connected to provide cooling to the heat exchangers.

Engineering Technical Evaluation ETE-CPR-2012-0011 concluded that containment pressure remains below design limits, and that key parameter instruments subject to containment environment will remain functional for at least 7 days. To remain within analyzed limits for equipment qualification temperature, the containment temperature will be procedurally monitored and, if necessary, the temperature will be reduced. This will require the implementation of the Phase 3 containment cooling strategy such that heat removal from containment is initiated in a timely manner.

The strategy to reduce Containment temperature is to provide containment ventilation cooling using the Containment Air Recirculation (CAR) system fans or the CRDM fans. This strategy requires repowering a Class 1 E 4160 Vac and 480 Vac bus using a 4160 Vac DG from the NSRC and restoration of cooling water flow (Service Water) to the Component Cooling Water (CC) heat exchanger.

An alternate strategy is also available which will provide for containment heat removal through water spray into the containment atmosphere using portable pumps, the installed RS system pumps, and containment spray (CS) rings. This strategy requires repowering a Class 1 E 4160 Vac and 480 Vac bus using a 4160 Vac DG from the NSRC and restoration of cooling water flow (Service Water) to the RS heat exchanger.

Primary Containment Cooling Strategy - Containment Ventilation Cooling

The 4160 Vac generator from the NSRC will be aligned to power a Class 1 E 4160 Vac and 480 Vac bus, which will provide power to CC system 4kV motors and CAR fan 480 Vac motors. Containment ventilation flow will be established by starting the CAR fan with air flow through the CAR fan coil unit and recirculating within the containment. Instrument Air (IA) system pressure will be restored, or portable compressed air bottles will be utilized, to operate valves to align CC water flow to the CAR fan coil unit. The SW system flow will be established from the Intake Canal through a CC heat exchanger to provide a heat sink, and CC flow will be established through the CAR fan coil unit and the CC heat exchanger to transfer heat to the SW system. In this manner, containment atmosphere heat will be rejected to the ultimate heat sink via the recirculation of containment atmosphere through the CAR fan coil unit.

The SW system flow will be provided to the CC heat exchanger by filling the Circulating Water (CW) system Intake Canal, if necessary, and maintaining level within the canal using the diesel-driven Emergency Service Water (ESW) pumps located at the Low-Level Intake Structure in the seismic Class I Emergency Service Water Pump House. Once sufficient Intake Canal level is established (within approximately 40 hours from empty with one of three ESW pumps operating), the flowpath through the CC heat exchanger will be aligned and water flow established by gravity flow consistent with normal system operation. In the event that the ESW pumps are unavailable, the Intake Canal level will be maintained by a NSRC low pressure / high flow pump drawing from the James River and discharging to the Intake Canal. In the event that the CW Intake Canal is not available, SW flow can be provided to the RS heat exchanger by pumping water from the discharge Canal to the SW system using an NSRC low pressure / high flow pump. The NSRC low pressure / high flow pump will draw from the discharge Canal through a strainer and discharge to the SW system through a 24" flanged manway connection in the piping, located below the Turbine Building floor slab, using a hose adapter. This connection is in a seismically-designed portion of the SW system, which is protected from high wind generated missiles. System alignments will be made to direct flow through the CC heat exchanger.

Alternate Containment Cooling Strategy - Containment Recirculation Spray

The 4160 Vac generator from the NSRC will be aligned to power a Class 1 E 4160 Vac and 480 Vac bus, which will provide power to the RS pump 480 Vac motor. Initially water from the RWST will be pumped through the spray ring header nozzles into Containment using the BDB [beyond design basis or FLEX] auxiliary feedwater (AFW) pump or the NSRC low pressure / medium flow pump connected to the BDB RCS [reactor cooling system] Pump Suction connection and discharging to the BDB Blind Flange connection, both located in the CSPH. This initial flow will provide heat removal from the Containment atmosphere and will fill the Containment sump in preparation for initiation of Containment RS flow. When the Containment sump level is adequate, an RS pump will be started to draw water from the sump and recirculate flow through an RS heat exchanger and the spray ring nozzles. The SW system flow will be established through the RS heat exchangers to provide a heat sink. In this manner, Containment atmosphere heat will be rejected to the ultimate heat sink via the sump water recirculation spray flowpath.

The RWST is not high wind and associated missile protected, and if unavailable as a water source to fill the Containment sump, adequate sump inventory can be provided from the CP Settling Pond. Raw water from this source can be pumped to the suction of the BDB AFW pump using the BDB High Capacity pump. Water strainers are provided at the suction of the BDB High Capacity pump for this use to prevent clogging of the CS ring header nozzles.

The CSPH is Seismic Category 1 but is not high wind and associated missile protected. The connections needed for the Containment spray option are located inside the CSPH and are protected for high winds, earthquakes, flooding, extreme cold, ice and snow, and extreme high temperature.

The SW system flow will be provided to the RS heat exchanger by filling the CW system Intake Canal, if necessary, and maintaining level within the canal using the diesel-driven ESW pumps located at the Low-Level Intake Structure in the seismic Class I Emergency Service Water Pump House. Once sufficient Intake Canal level is established (within approximately 40 hours from empty with one of three ESW pumps operating), the flowpath through the RS heat exchanger will be aligned and water flow established by gravity flow consistent with normal system operation. In the event that the ESW pumps are unavailable, the Intake Canal level will be maintained by a NSRC Low Pressure / High Flow pump drawing from the James River and discharging to the Intake Canal. In the event that the CW Intake Canal is not available, SW flow can be provided to the RS heat exchanger by pumping water from the Discharge Canal to the

SW system using an NSRC Low Pressure / High Flow pump. The NSRC Low Pressure / High Flow pump will draw from the Discharge Canal through a strainer and discharge to the SW system through a 24" flanged manway connection in the piping, located below the Turbine Building floor slab, using a hose adapter. This connection is in a seismically-designed portion of the SW system, which is protected from high wind generated missiles. System alignments will be made to direct flow through the RS heat exchanger.

3.4.4 Staff Evaluations

3.4.4.1 Availability of Structures, Systems, and Components

In 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

From Section 6.3 of the UFSAR: The containment spray system safety related components, piping, valves, and supports in the spray system are Seismic Category I. The spray pumps and valves are fabricated, welded, and inspected according to the requirements of the applicable portions of the American Society of Mechanical Engineers (ASME) Code, Sections III, VIII and IX. Materials of construction are stainless steel or equivalent corrosion-resistant materials.

Heat exchangers and vessels are designed to ASME Code, Section VIII, Division 1, and have been radiographed in accordance with ASME Code Section VIII to ensure their structural integrity. Heat exchangers and vessels are of welded construction to preclude leakage.

Electrical insulation for motors located outside containment is in accordance with American National Standards Institute (ANSI), Institute of Electrical and Electronics Engineers (IEEE), and National Electrical Manufacturers Association (NEMA) standards, and is tested as required by these standards. Temperature rise design is such that normal long life is achieved even under accident loading conditions.

The containment motors have been selected to ensure operation during LOCA conditions. Motor electrical insulation is in accordance with ANSI, IEEE, and NEMA standards. The motors are tested, as required, by these standards. Bearings are antifriction type. Bearing loading and high-temperature tests have been performed, and the expected bearing life equals, or exceeds, that specified by the Anti Friction Bearing Manufacturers Association (AFBMA).

The four recirculation spray pumps take suction from a common containment sump strainer assembly. Each recirculation spray pump has a rated capacity of 3500 gpm. Two of the recirculation spray pumps and motors are located inside the containment structure, and two pumps and motors are located outside the containment.

Each of the containment spray headers draws water independently from the refueling water storage tank. The tank is designed as a Class I component, as described in UFSAR Section

2.5, to withstand design seismic loading in accordance with the design stress criteria of ASME Code Section III. The connecting piping is designed to withstand seismic loading to ensure the functioning of the system.

In the UFSAR, Table 15.2-1 indicates the component cooling system is seismic Criterion 1 and is protected in a tornado resistant structure. Service water piping to the CC heat exchangers is seismic Criterion Class 1 and is in tornado-resistant structures.

From UFSAR Section 9.4, component cooling water pumps have corrugated metal expansion joints installed close to the pump suctions and discharges. These joints isolate the pumps design so pump rupture is unlikely. Each unit can be isolated and each unit should be able to carry full load. The standby unit intended for one reactor unit may be used for the other unit by repositioning valves.

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 will 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, will be available using alternate methods. Instruments providing key parameters are: Containment Pressure, Containment Wide Range Temperature, and Containment Sump Level (only credited for containment cooling spray option).

3.4.4.2 Thermal-Hydraulic Analyses

Evaluations have been performed and conclude that containment temperature and pressure will remain below design limits and key parameter instruments subject to the containment environment will remain functional for at least 7 days (reference Calculations MISC-11793 and MISC-11794). Therefore, actions to reduce containment temperature and pressure and ensure continued functionality of the key parameters will not be required prior to this time and will utilize off site equipment and resources during Phase 3.

During the site audit, NRC staff reviewed calculation MISC-11793, "Evaluation of Long Term Containment Pressure and Temperature Profiles Following Loss of Extended AC Power (ELAP)," Revision 0, February 18, 2013. The NRC staff also reviewed calculation MISC-11794, "Evaluation of North Anna, Surry, and Millstone Containment Instrumentation Following Extended Loss of AC (ELAP)," Revision 0, February 18, 2013.

Calculation MISC-11793 utilizes the GOTHIC version 7.2a thermal-hydraulic computer code. Reactor coolant pump seal leakage is assumed to be 21 gpm/pump. An additional 1 gpm leakage is added for unidentified reactor coolant leakage. The calculation uses PWROG Generic Evaluation Letter LTR_LIS_11-595 (Reactor Coolant System Response for Extended Station Blackout), PWROG Project Authorization ASC-0916 (Task 1 Results Letter Report November 9, 2011), PWROG Generic Evaluation Letter LTR_LIS_11-657, (Transmittal of Mass and Energy Release Data for Westinghouse Designed NSSSS to Support PWROG PA-ASC-0916 – Task 1 Station Blackout (SBO) Coping Study, December 15, 2-11), and WCAP-17601-P Revision 0, Reactor Coolant System Response to the Extended Loss of AC Power Event for

Westinghouse, Combustion Engineering and Babcock & Wilcox NSSS Designs," August 2012. The calculation indicates that, at seven days, the containment pressure will be 23 psia and the containment temperature will be 193°F.

The calculation used the Environmental Qualification Management System (EQMS), Version 3.0, computer program to evaluate ELAP containment temperature and pressure profiles for seven days to provide some assurance of operation for post-accident instrumentation. The calculation determined plant design-basis accident pressures and temperatures exceed the ELAP temperature and pressure profiles.

3.4.4.3 FLEX Pumps and Water Supplies

Please refer to Section 3.2.3.5 for information on FLEX Pumps and Water Supplies.

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 required instrumentation function. With an ELAP/LUHS initiated, while either Surry 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/LUHS 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. 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 for a minimum of seven days. Therefore, actions to reduce containment temperature and pressure and to ensure continued functionality of the key parameters will not be required immediately.

The licensee's Phase 1 coping strategy for containment involves initiating and verifying containment isolation per ECA-0.0. These actions ensure containment isolation following an ELAP/LUHS. 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/LUHS. Containment temperature (taken at the 47' elevation) is available in the control room prior to load stripping and following repowering of the dc loads with either the 480 Vac or 120/240 Vac FLEX DGs.

The licensee's Phase 2 coping strategy is to continue monitoring containment temperature and pressure using installed instrumentation. Phase 2 activities to repower key instrumentation are required to continue containment monitoring. The licensee would monitor containment temperature periodically as directed by procedure and, if necessary, operators would take action to reduce containment temperature to ensure that key instruments inside containment remain within analyzed limits for equipment qualification. Containment temperature reduction requires the implementation of a containment cooling strategy utilizing equipment provided by an NSRC (Phase 3).

The licensee evaluated multiple options, including ventilation cooling or spray, to provide operators with the ability to reduce the containment temperature. Each of these options would require the restoration of multiple support systems to remove heat from the containment, thus reducing containment temperature and pressure. Necessary actions to reduce containment temperature and ensure continued functionality of the key parameters utilize existing plant systems powered by offsite equipment during Phase 3. 4160 Vac power is needed to operate various station pumps. This capability is provided by two 1 MW 4160 Vac portable combustion turbine generators per unit provided from an NSRC. The portable 4160 Vac combustion turbine generators and a distribution panel for each unit are brought in from an NSRC in order to supply power to either of the two Class 1E 4160 Vac buses on each unit. Additionally, by restoring a 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 licensee's preferred option is to establish containment ventilation by either establishing CARF cooling or establishing Control Rod Drive Mechanism (CRDM) cooling. To implement this option, the 4160 Vac combustion turbine generators from an NSRC would be aligned to power a Class 1E 4160 Vac bus and a 480 Vac bus. The 4160 Vac combustion turbine generators would provide power to the existing CC system, an IA system compressor, and one of the CARF or the CRDM fan motors. If SW is not available from the intake canal, then low pressure/high flow diesel driven pumps (up to 5,000 gpm) from the NSRC are available to provide flow to existing site heat exchangers to facilitate heat removal from the containment atmosphere. Operators would establish containment ventilation by starting either a CARF or CRDM fan, cooling with air flow through the respective cooling coil unit, and recirculating within the containment. The IA system pressure would be restored to remotely operate valves inside containment, as required.

A spray option is available to spray water into the containment as an alternative using the containment RS system utilizing clean water from the RWST or the CP Settling pond. To utilize this option, the 4160 Vac generators from an NSRC would be aligned to power one of the Class 1E 4160 Vac and 480 Vac buses on each unit, which provides power to the RS pump 480 Vac (or 4160 Vac, depending upon the selected pump) motor.

The spray flow would fill the containment sump in preparation for initiation of RS flow. When the sump level is adequate, an operator would start either an inside or outside RS pump to draw water from the sump and recirculate flow through the RS heat exchangers and the spray nozzles. The SW system flow would be established through the RS heat exchangers to provide a heat sink in the same manner as the CC heat exchanger flow is established in the ventilation option. In this manner, Containment atmosphere heat is rejected to the ultimate heat sink via the sump water recirculation spray flow path.

The staff reviewed calculation EE-0872, and determined that the electrical equipment that will be supplied from an NSRC (i.e., two 1-MW 4160 Vac combustion turbine generators and distribution panel) has sufficient capacity and capability to supply the required loads to reduce containment temperature and pressure, if necessary, to ensure that key instrumentation remains 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 guidance, 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, Revision 0, 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 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. No external hazards, from those described in NEI 12-06, were screened out.

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* (10 CFR) Part 50, Section 50.54(f) [Reference 19] (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* (November 13, 2015, 80 FR 70609) [Reference 51]. 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" [Reference 48]. The Commission provided guidance in an SRM to

COMSECY-14-0037 [Reference 20]. 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 [Reference 36], the NRC staff informed the licensees that the implementation of mitigation strategies should continue as described in licensee's OIPs, and that the NRC SEs 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 [Reference 52]. The NRC staff endorsed Revision 2 of NEI 12-06 in JLD-ISG-2012-01, Revision 1 [Reference 53]. The licensee's MSAs will evaluate the mitigating strategies described in this SE using the revised 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 stated that seismic hazards are applicable to the site. From the FIP, the Surry seismic hazard is considered to be the earthquake magnitude associated with the design-basis seismic event. Per Section 2.5.6 of the Surry UFSAR, the design-basis earthquake is 0.15g for horizontal ground motion and 0.10g for vertical ground motion.

As previously discussed, the NRC issued a 50.54(f) letter [Reference 19] that requested facilities to reevaluate the site's seismic hazard. In addition, the 50.54(f) letter requested that licensees submit, along with the hazard evaluation, an interim evaluation and actions planned or taken to address the reevaluated hazard where it exceeds the current design-basis seismic hazard.

By letter dated March 31, 2014 [Reference 22], the licensee submitted its Seismic Hazard and Screening Report for Surry, Unit Nos. 1 and 2, to the NRC. The licensee concluded in its report and restated this conclusion in its FIP, that seismic reviews performed for initial plant licensing bounded the ground motion response spectrum (GMRS) in the 1 to 10 Hertz (Hz) frequency range and concluded that performance of further seismic risk evaluation was not required for Surry.

The NRC endorsed industry guidance "Seismic Evaluation Guidance: Screening, Prioritization and Implementation Details (SPID) for the Resolution of Fukushima Near-Term Task Force Recommendation 2.1: Seismic," (ADAMS No. ML12333A170) provides the criteria used to determine if the licensee's individual plant examination for external events (IPEEE) submittal is adequate to use for seismic screening purposes. However, if one or more of the criteria are not deemed adequate, the staff may still decide that the overall IPEEE analysis is adequate to support its use for seismic screening.

On October 3, 2014, the NRC updated its screening and prioritization determination [Reference 49] and concluded that for Surry, the safe shutdown earthquake (SSE) bounds the GMRS and therefore screens out of any further evaluations. In addition, on October 27, 2015, the NRC issued the final determination of licensee seismic probabilistic risk assessments [Reference 50] which, for Surry, Unit Nos. 1 and 2, included a footnote under the high frequency limited scope evaluation that stated, “Evaluation no longer expected based on de minimis exceedance above design-basis SSE.”

If for any other reason, additional seismic review activities are conducted in the future, the licensee should address any safety issues by implementing appropriate corrective actions. Based on the above, the staff concludes that 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 described that the probable maximum hurricane (PMH) is the most severe meteorological event at the Surry site and results in the most limiting flood level elevations at both the site and the intake structure. During a PMH, the James River stillwater level is 22.7 feet at the site. Accounting for maximum wave runup, the flood level of a PMH at the east end of the site, the intake structure, is approximately 28.6 feet. The east face of the intake structure is protected against this wave action. The intake structure is located more than a mile from the main site (power block) structures and has no credited role in the FLEX strategies for Surry. Maximum runup due to storm surges at the west side of the main site is 24 feet MSL. Critical equipment in this area is protected against flooding to elevation 26.5 feet, which is the typical site grade.

The licensee has submitted its Flood Hazard Reevaluation Report (FHRR) [Reference 21]. The licensee identified local intense precipitation (LIP) resulting from the site-specific probable maximum precipitation as the bounding event that exceeds the current licensing basis flood level. The NRC staff issued an interim staff assessment of the FHRR [Reference 45] and concluded that the licensee's reevaluated flood hazards information is suitable for the assessment of mitigating strategies developed in response to Order EA-12-049 (i.e., defines the mitigating strategies flood hazard information described in NEI 12-06 for Surry). Further, the NRC staff concluded that the licensee’s reevaluated flood hazard information is a suitable input for other assessments associated with NTTF Recommendation 2.1 “Flooding”. The NRC staff plans to issue a staff assessment documenting the basis for these conclusions at a later time. In order to complete its response to the information requested by Enclosure 2 to the 50.54(f) letter, the licensee is expected to submit an integrated assessment or a focused evaluation, as appropriate, to address these reevaluated flood hazards, as described in the NRC letter dated September 1, 2015 [Reference 36].

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 MBDBE rulemaking. The licensee has appropriately screened in this external hazard and identified the hazard levels to be evaluated.

3.5.3 High Winds

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/year, the site should address hazards due to extreme high winds associated with hurricanes.

The screening for high wind hazards 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.

In its FIP, the licensee stated that the plant design bases address the storm hazards of hurricanes, high winds, and tornadoes. In its FIP, the licensee also stated that for extreme straight winds - UFSAR Table 2.2-1 listed the fastest mile wind in Norfolk as 78 miles per hour (mph) and in Richmond as 68 mph, both occurring in October 1954 during the passing of Hurricane Hazel. For tornados and tornado missiles, the Surry UFSAR indicates that between January 1951 and December 1987, there were a total of 49 tornados reported within a 50-mile radius of the site. For tornadoes and tornado missiles, the tornado model used for design purposes has a 300-mph rotational velocity, a 60 mph translational velocity, and a pressure drop of 3 pounds per square inch (psi) in 3 seconds. Wind generated missiles include a utility pole and a 1 ton vehicle traveling at 150 mph. On April 16, 2011, a tornado struck the Surry Power Station switchyard, which caused damage to equipment in the switchyard resulting in a loss of offsite power and reactor trips on both Units 1 and 2.

The NRC staff referred to applicable guidance in NEI 12-06 to confirm the wind hazard information. Based on the information in the FIP and the information in the applicable guidance, the staff found that high-wind hazards are applicable to the plant site. Therefore, the staff concludes that 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.

The climatic characteristics of the site region are influenced by the Atlantic Ocean, the Chesapeake Bay, and the Appalachian Mountains. The Atlantic Ocean has a moderating effect on the temperature for the Surry region, whereas the Appalachians act as a barrier to deflect Midwest winter storms to the northeast of the Surry region. Snow is not common during winter in the Tidewater area of Virginia. A snowfall of 10 inches or more a month in the Tidewater area is expected to occur once every 4 years. In general, the total accumulated snow for the Tidewater is approximately 10 inches each year. Precipitation occurs mostly as rain in the site area. The maximum monthly snowfall in Norfolk was 18.9 inches in February 1980 and the maximum monthly snowfall for Richmond was 28.5 inches in January 1940. The lowest temperature recorded in Norfolk was minus 3 °F in January 1985 and in Richmond was minus 12 °F in January 1940. The Surry UFSAR does not provide historical data on ice storms in the site characterization; however, ice storms can occur at Surry Power Station and may cause hazardous travel and downed trees, which may block the site access road and possibly deployment haul paths.

The NRC staff verified that the site is located at latitude 37° 09' 56" North and longitude 76° 41' 52" West. In addition, the site is located within the region characterized by EPRI as ice severity level 4 (NEI 12-06, Figure 8-2, Maximum Ice Storm Severity Maps). Consequently, the site is subject to icing conditions that could cause severe damage to electrical transmission lines. The licensee concluded that the plant screens in for an assessment for snow, ice, and extreme cold hazard. In its FIP, the licensee stated that FLEX equipment is protected from severe temperatures.

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 hazards of snow, ice, and extreme cold.

3.5.5 Extreme Heat

Per NEI 12-06 Section 9.2, all sites are required to consider the impact of extreme high temperatures. In its FIP, the licensee stated that the Atlantic Ocean has a moderating effect on the temperature for the Surry region. The peak temperature recorded in Norfolk was 104 °F in August 1980 and in Richmond was 105 °F in July 1977.

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. Therefore, 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 guidance, as endorsed, by JLD-ISG-2012-01, and adequately addresses the requirements of the order in regard to the characterization of external hazards.

3.6 Planned Protection of FLEX Equipment

3.6.1 Protection from External Hazards

In its FIP, the licensee indicated that the BDB equipment, with the exception of the 10 CFR 50.54(HH)(2) pump [licensee uses this pump as the N+1 high capacity pump], is stored in a single 10,000 square foot concrete building that is located on the south side of the site adjacent to the protected area. The BDB storage building was designed and constructed to protect the equipment from the hazards applicable to Surry.

In its FIP, the licensee stated that the 10 CFR 50.54(hh)(2) high capacity pump is stored in the emergency response building on site, which is reasonably protected from flooding, extreme heat, and extreme cold hazards. The emergency response building does not meet the requirements of NEI 12-06 Sections 5.3.1 (seismic) and 7.3.1 (high winds) because it is not fully protected against a seismic hazard and high wind hazards. Therefore, the storage arrangements for the 10 CFR 50.54(hh)(2) pump represent an alternate approach to the requirements of NEI 12-06, Sections 5.3.1, 7.3.1, and 11.3.3. This alternative approach is discussed in Section 3.14 of this SE.

The debris removal equipment required to support the implementation of the FLEX strategies is also stored inside the BDB storage building in order to protect them from the applicable external hazards. Therefore, the equipment remains functional and deployable to clear obstructions from the pathway between the BDB equipment's storage location and its deployment location(s). Below are additional details on how FLEX equipment is protected from each of the external hazards.

3.6.1.1 Seismic

The FIP states that the BDB storage building was evaluated for the effect of local seismic ground motions consistent with the Surry GMRS developed for the original site licensing basis and was found to have adequate structural margin to remain functional (i.e., collapse is not expected and access to the interior should be retained). Analysis of components stored in the BDB storage building has been performed to determine appropriate measures to prevent seismic interaction. The fire protection and HVAC systems in the BDB storage building are seismically installed. The lighting, conduits, electrical, and fire detection components are not seismically installed, but are considered insignificant and not able to damage BDB equipment.

As previously stated, the alternate approach to the use of the 10 CFR 50.54(hh)(2) high capacity pump, which is not fully protected against a seismic event, is discussed in Section 3.14 of this SE.

3.6.1.2 Flooding

In its FIP, the licensee stated that the BDB storage building is located on the south side of the site adjacent to the protected area. This location is above the flood elevation from the most recent site flood analysis.

In its FIP, the licensee stated that the 10 CFR 50.54(hh)(2) high capacity pump is stored in the emergency response building on site, which is reasonably protected from flooding.

3.6.1.3 High Winds

As previously stated, the BDB storage building meets the plant's design-basis for external hazards applicable to Surry, including protection from tornado missiles.

As previously stated, the alternate approach to the use of the 10 CFR 50.54(hh)(2) high capacity pump, which is not fully protected against high wind/tornado missile, and hurricane events, is discussed in Section 3.14 of this SE.

3.6.1.4 Snow, Ice, Extreme Cold and Extreme Heat

In its FIP, the licensee indicated that HVAC equipment is installed in the BDB storage building. In addition, the 10 CFR 50.54(hh)(2) high capacity pump is stored in the emergency response building on site, which is reasonably protected from extreme heat, and extreme cold hazards.

3.6.2 Reliability of FLEX Equipment

In its FIP, the licensee provided a table that lists the portable equipment stored onsite to be used to mitigate a BDB event. Included in the list are two BDB high capacity pumps and associated hoses and fittings (the N+1 pump is the 10 CFR 50.54(hh)(2) pump); three BDB AFW pumps and associated hoses and fittings; two RCS injection pumps and associated hoses and fittings; three 120/240 Vac generators and associated cables, connectors and switchgear; two 480 Vac generators and associated cables, connectors and switchgear; three portable boric acid batching tanks; one fuel transfer truck with 1,100 gallon tank and pumps; fuel cart with transfer pumps; communication equipment; miscellaneous debris removal equipment; front end loader; tow vehicles; hose trailer and utility vehicle; fans/blowers; air compressors; portable lighting equipment; and other miscellaneous equipment.

In its FIP, the licensee stated that sufficient equipment has been purchased to address the required functions at both units on-site, plus one additional spare, i.e., an N+1 capability. Therefore, where a single resource is sized to support the required function of both units a second resource has been purchased to meet the +1 capability. The existing 50.54(hh)(2) pump is counted toward the N+1, since it meets the functional requirements outlined in NEI 12-06. However, the N+1 50.54(hh)(2) pump storage in the emergency response building represents an alternative to NEI 12-06 because the building is not fully protected against seismic, high wind/tornado missile, and hurricane events. This alternative is discussed in section 3.14. In addition, where multiple strategies to accomplish a function have been developed, (e.g., two separate means to repower instrumentation) the equipment associated with each strategy does not require N+1 capability.

The licensee stated in its FIP that the N+1 requirement does not apply to the BDB FLEX support equipment, e.g., vehicles, and tools. However, these items are covered by a fleet administrative procedure and are subject to inventory checks, unavailability requirements, and any maintenance and testing that are needed to ensure they can perform their required functions.

In its FIP, the licensee stated that in the case of hoses and cables associated with FLEX equipment required for FLEX strategies, an alternate approach to meet the N+1 capability has been selected. Details of this alternate strategy are discussed in Section 3.14 of this SE.

As stated above, for SG and SFP makeup strategy, the licensee relies on two BDB high capacity pumps; the 10 CFR 50.54(hh)(2) high capacity pump stored in the emergency response building, and the high capacity pump stored in the BDB Storage Building. Because the licensee is relying on only two BDB high capacity pumps to fulfill the N+1 capability, the NRC requested confirmation during the audit process that the capacity of one BDB high capacity pump can simultaneously supply 300 gpm flow to each unit's SG and 500 gpm to the dual unit SFP. The licensee stated in the Surry, Unit No.1 compliance letter [Reference 18] that calculation ME-0967, Rev. 0 confirmed the ability of the BDB high capacity pump to simultaneously deliver at least 300 gpm to each unit's AFW system and at least 500 gpm to the SFP with margin for pump placement. A review of the calculation confirmed that the 10 CFR 50.54(hh)(2) high capacity pump (N+1) was included in the calculation to confirm adequate capacity.

The alternate strategy for SG makeup is provided for with three BDB (FLEX) AFW pumps sized at a nominal 450 psid at 300 gpm pump. The BDB AFW pump is a trailer-mounted, diesel engine driven centrifugal pump that is stored in the BDB storage building protected against all applicable hazards. The portable, diesel-driven BDB AFW pump provides a back-up method for SG injection in the event that the TDAFW pump can no longer perform its function due to insufficient turbine inlet steam pressure. This FLEX AFW pump is sized to provide the minimum required SG injection flowrate to support reactor core cooling and decay heat removal for one unit. Three FLEX AFW pumps are available to satisfy the N+1 requirement.

For the RCS injection strategy the licensee relies on two BDB RCS injection pumps. In the event of a failure of one of the pumps, the pump design capacity is such that a single pump can be shared between the units, thus meeting the N+1 requirement with two pumps. Because the licensee is relying on only two BDB RCS injection pumps to fulfill the N+1 capability, during the audit process the NRC requested confirmation that intermittent use of the RCS injection pump between units is adequate using only one RCS injection pump. The licensee stated in the Surry, Unit No.1 compliance letter [Reference 18] that the unlikely worst-case scenario for RCS injection is when only one BDB RCS injection pump is available and both RWSTs are unavailable and provided a detailed justification to show that intermittent use of one RCS injection pump is adequate. Since two portable boric acid mix tanks (BAMTs) are needed to provide the capability to batch one tank while the other tank is being injected, the licensee obtained a third BAMT in order to meet the N+1 requirement.

For the electrical repowering strategies, the licensee employs two 120/240 and 480 Vac diesel generators to repower battery chargers and various electrical panels. Each unit requires one 480 Vac portable diesel generator for this purpose, and the licensee maintains two of these DGs stored in the FLEX storage building. One 120/240 Vac 40kW portable diesel generator per unit is available as an alternate re-powering option per unit. The licensee stated in its FIP that they maintain two of these generators in the FLEX storage building; however, the use of the 120/240 Vac DGs is an alternate strategy to the 480 VAC generators, therefore only 2 are required.

Additional replacement 480 VAC generators and 4160 VAC diesel powered generators are available from the NSRC for the Phase 3 strategy.

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, with the exception of the 10 CFR 50.54(hh)(2) pump, and should adequately address the requirements of the order. Refer to Section 3.14 for the evaluation of the alternate storage strategy for the 10 CFR 50.54(hh)(2) pump.

3.7 Planned Deployment of FLEX Equipment

The licensee stated in its FIP that the deployment of onsite BDB equipment in Phase 2 requires that pathways between the BDB storage building and various deployment locations be clear of debris resulting from BDB events. Pre-determined FLEX strategy equipment haul paths have been identified and documented in the licensee's FSGs. Figure 22 in the FIP shows the haul paths from the BDB Storage Building to the various deployment locations.

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. Delivery of this equipment can be through airlift or via ground transportation.

The licensee stated in the Surry, Unit No. 1 compliance letter that the NSRC local staging areas, access route evaluations, and transportation evaluations to the site have been completed and documented in the SAFER Trip Report for Surry Power Station. The SAFER Response Plan for Surry has also been finalized.

3.7.1 Means of Deployment

In its FIP, the licensee stated that the debris removal equipment includes mobile equipment such as a front-end loader and tow vehicles (tractors) equipped with front-end buckets and rear tow connections for moving or removing debris from the needed travel paths. A front-end loader is also available to deal with more significant debris conditions. Deployment of the debris removal equipment and the Phase 2 BDB equipment from the BDB storage building is not dependent on offsite power. The building equipment doors are hydraulically operated with a battery backup and can also be opened manually.

Debris removal for the pathway between the site and the NSRC receiving "staging areas" locations and from the various plant access routes may be required. The same debris removal equipment used for onsite pathways may also be used to support debris removal to facilitate road access to the site once necessary haul routes and transport pathways onsite are clear. The debris removal equipment should enable the licensee to clear debris generated by the applicable external hazards from deployment pathways.

3.7.2 Deployment Strategies

In its FIP, the licensee stated that pre-determined FLEX strategy equipment haul paths have been identified and documented in the FSGs and depicts the haul paths from the BDB storage building to the various deployment location. These haul paths have been reviewed for potential soil liquefaction and have been determined to be stable following a seismic event. Additionally, the haul paths minimize travel through areas with trees, power lines, narrow passages, etc. to the extent practical. However, high winds can cause debris from distant sources to interfere with these haul paths. Debris removal equipment is stored inside the BDB storage building can be deployed to clear obstructions from the pathway between the BDB equipment stored in the BDB storage building and its deployment location(s).

In response to an audit question on potential ice where the BDB high capacity pump takes suction, the licensee stated that the suction for the BDB high capacity pump would be taken from the discharge canal. The BDB high capacity pump and suction line with an inline floating strainer will be deployed into the discharge canal when augmented staff arrive on-site at 6 hours, or sooner. Some degree of warm water would be available in the discharge canal to prevent freezing even with both units shutdown. However, in the event that ice was present on the surface of the discharge canal, tools and equipment will be available in the BDB storage building to create an opening in the ice in order to drop the suction line and strainer into the canal.

3.7.3 Connection Points

3.7.3.1 Mechanical Connection Points

Core Cooling

Primary and Alternate SG Makeup Connection (BDB AFW pump discharge)

In the FIP, Section 2.3.5.1 states that the primary SG makeup connection point injects into the TDAFW pump discharge piping that feeds all three SGs. The connection is a pipe tee on the existing AFW line that contains a hose connection and isolation valve that is normally closed. As described in the UFSAR Table 15-2, Rev. 43, the AFW system pumps and piping are Seismic Class I and tornado missile protected. During the onsite audit, the staff noted the primary AFW connection was located in the lower level of the MSVH. In the FIP, Section 2.3.5.2 states that the alternate connection is located in the AFW cross-connect piping between the two units. More specifically, the alternate FLEX piping connects to the cross-connect piping in the opposite units MSVH. The bonnet assembly of one of two AFW cross-connect MOVs is removed and a flanged temporary hose connecting adapter is installed on the valve. The primary and alternate connection points share common piping depending on the chosen flow paths. However, operators can configure the system such that the primary and alternate connection points would provide independent flow paths to the individual SGs. Based on the design and location of the primary and alternate AFW connection points, as described in the FIP and UFSAR, at least one of the connection points should be available to support core cooling via a portable pump during an ELAP caused by a BDBEE, consistent with NEI 12-06, Section 3.2.2 and Table D-1.

<u>BDB High Capacity pump discharge and BDB AFW pump suction</u>

In the FIP, Section 2.3.5.3 states that a permanent connection is installed on the TDAFW pump suction line near the ECST discharge nozzle to refill the ECST and also provides suction for the BDB AFW pump. Furthermore, the FIP states the connection is seismically robust and is located inside the tornado missile barrier enveloping the ECST. As stated earlier, operators can align the BDB High Capacity pump to refill the ECST or discharge directly to the suction of the BDB AFW pump.

RCS Inventory Control/Makeup

<u>BDB RCS Injection Pump</u>

In the FIP, Section 2.3.5.4 states that the discharge from the FLEX RCS makeup pump will be a 3" connection downstream of the Low Head Safety Injection (LHSI) pump discharge MOVs which inject into the RCS hot legs. Three inch piping is routed from the LHSI pump discharge up through two floor to the 28'-6" level near the personnel access door to the Safeguards Building. As described in UFSAR Table 15.2-1, Rev. 43, the LHSI pumps and piping is Seismic Class I and located in the structure protected from tornado wind and missiles. The entrance to the Safeguards Building is above the maximum flood height. Additionally, FIP Section 2.3.5.5 states that the alternate RCS connection is located in the basement of the Auxiliary Building. Specifically, a hose connection adapter can be installed on the 2" blind flanged connection on the charging pump discharge header and injection can be lined up to any of the three loop cold leg safety injection paths or alternate aligned for injection to the three hot leg safety injection paths. The charging system is classified in UFSAR Table 15.2-1, Rev. 43, as a Seismic Class I system located in a tornado-protected structure. An intermediate standpipe (permanent piping) has been installed and routed from the Auxiliary Building basement to a stair landing near the Auxiliary Building outside access door so operators will not have to route hoses down to the basement. As described in the UFSAR, Table 15.2-1, Rev. 43, the Auxiliary Building is a Seismic Class I structure that is protected from a design-basis tornado. The staff noted the outside access is located above the max flood height of 24' MSL.

In NEI 12-06, Table D-1, states, in part, that the performance attributes for make-up with a portable pump should include primary and alternate injection points to establish capability to inject through separate divisions/trains, i.e., should not have both connections in one division/train. During the onsite audit, the staff noted that elevation 28'-6" of the Safeguards Building (location of primary RCS injection connection) is not fully tornado missile protected. However, the alternate connection is located in the Auxiliary Building basement and is protected from a design basis tornado. The staff finds this acceptable because NEI 12-06 Section 3.2.2 states in part, that the both the primary and alternate connections points do not need to be available for all applicable hazards. Based on the licensee's description and associated diagrams in the FIP, the staff finds the licensee is consistent with NEI 12-06, Table D-1, as the licensee has the capability of RCS make-up with a portable pump through primary and alternate injection points to inject through separate divisions/trains.

<u>Primary and Alternate RCS Suction Piping (FLEX pump suction)</u>

In the FIP, Section 2.3.5.6 states that the primary supply of water to the BDB RCS Injection pump is through a suction connection from the RWST via permanently installed hose connection. The connection points are installed in both CSPHs on the suction of the Containment Spray pumps. In the UFSAR, Table 15.2-1 lists the CSPH as Seismic Class I. However, the CSPH is not fully tornado missile protected, so either units RWST can provide borated water to both units if necessary. Furthermore, the licensee has portable boron mixing tanks stored in the BDB Storage Building that can provide borated water for the BDB RCS Injection pump. The staff noted that the primary and alternate RCS FLEX pump suction connection points were either designed and/or located in a robust structure such that at least one connection point should be available during an ELAP event, which is consistent with NEI 12-06, Section 3.2.2.

SFP Cooling

In the FIP, Section 2.4.4.1 states that the primary connection for SFP makeup will be a hose connection on the permanent, seismically designed BDB SFP makeup connection line located on the outside wall of the Fuel Building. The new BDB SFP makeup connection line is a 4-inch line that tees into the existing 6-inch emergency SFP makeup line. The existing line runs along the inside of the north wall (concrete) of the Fuel Building between the 21'-6" and the 27' elevations. The new seismically supported 4-inch line is routed from the new tee to the exterior connection location. The exterior connection is outside wall of the Fuel Building at the 31' elevation near the Primary Grade pump house. Check valves are installed in the line to prevent inadvertent backflow. The FIP states that the new connection is a standard fire hose connection and is protected by tornado missile shield. Use of the primary BDB SFP makeup connection will not require entry into the Fuel Building. The alternate Phase 2 strategy for providing makeup water to the SFP is to use the SFP refill equipment that is already in place. The FP system feeds the emergency SFP makeup line from the yard fire main loop. The emergency SFP makeup line extends above the SFP so that water can be discharged directly into the pool. The water source for the alternate strategy is the pressurized fire main, which can be pressurized by the site Fire Pump, if available, or the BDB High Capacity pump. The FIP states that the yard fire main is buried and seismically qualified, and is expected to be able to provide water during a flooding event. As described in UFSAR Table 15.2-1, Rev. 43, the Fuel Building is Seismic Class I and design to withstand a design-basis tornado. Additionally, the SFP Cooling system piping is listed as Seismic Class I and is housed in the Fuel Building, which is protected from all applicable hazards. The staff noted that the primary and alternate SFP cooling connection points were either designed and/or located in a robust structure such that at least one connection point should be available during an ELAP event, which is consistent with NEI 12-06, Section 3.2.2. Additionally, as outlined earlier, the licensee can also route hoses from the BDB High Capacity pump discharge directly to the SFP to either fill or spray water into the pool eliminating the need for either connection.

3.7.3.2 <u>Electrical Connection Points</u>

The licensee's primary FLEX strategy for re-powering 120 Vac vital bus circuits during Phase 2 is through the use of pre-installed connections and the deployment of one 480 Vac FLEX DG per unit connected to the Class 1E 480 Vac bus. The 480 Vac FLEX DG allows for recharging the Class 1E batteries and for restoring other ac loads in addition to key parameter monitoring instrumentation. Operators would deploy the portable 480 Vac DGs and their associated cables from the BDB Storage Building to the alleyways on the west and east sides of the Auxiliary Building. The licensee added a 480 Vac distribution panel to each 480 Vac FLEX DG trailer that splits the load side of the 480 Vac DG output breaker into two circuits. Connection receptacles for both circuits are located on the pre-installed receptacle panel. The power cables would be connected to seismically-designed, tornado-missile protected, connection receptacles in each unit's Upper Cable Vault. The connection receptacles in the Upper Cable Vaults are connected to the Class 1E 480 Vac bus via pre-installed cable and conduit to Class 1E 480 Vac motor control center (MCC) breakers. 1(2)-FSG 4, provides direction for ensuring proper phase rotation before attempting to power equipment from the 480 Vac FLEX DGs (a phase rotation meter is provided in the receptacle panel for each 480 VAC circuit).

The licensee's alternate strategy for re-powering 120 Vac vital bus circuits during Phase 2 is to use one 120/240 Vac DG per unit connected to the 120 Vac vital buses through pre-installed BDB receptacle panels, cabling, connections, and distribution panels. The portable 120/240 Vac DGs are stored in the BDB Storage Building and would be deployed to the alleyways east of the Auxiliary Building for Unit 1 and west of the Auxiliary Building for Unit 2. The DGs would be connected via cables to receptacle panels located in the Upper Cable Vault of each unit. From the receptacle panel, cables are installed in seismically mounted raceways to two distribution panels, one for each of the 120/240 VAC DG output circuits. The 120/240 Vac cables for each unit are stored on two 100' cable reels located in each unit's Upper Cable Vault. Backup cables would be transported from the BDB Storage Building on the same cable trailer as the 480 Vac cables for that unit. Each 120/240 Vac DG has two output circuits that supply two BDB distribution panels which provide power to essential instrumentation, lighting, and battery room exhaust fans. The BDB receptacle in each unit's Upper Cable Vault is connected to the BDB distribution panels via pre-installed cable and conduit.

For Phase 3, the licensee will receive two 1-MW 4160 Vac combustion turbine generators from an NSRC. The two 1-MW 4160 Vac combustion turbine generators would be connected to the distribution panel in order to meet the required 4160 Vac load requirements for each unit. Due to the size of the equipment, the licensee would deploy the 4160 Vac turbine generators to areas either near the Truck Bay area south side of the Unit 2 Turbine Buildings or by the existing EDG Rooms. Depending on the debris situation, the Turbine Building Truck Bay opening may be the more viable option for deployment. In this case, the Emergency Switchgear Room would be used to tie the 4160 Vac turbine generators to one of the two Class 1E 4160 Vac buses for each unit. From the Truck Bay opening location, connections to energize the Class 1E 4160 Vac buses can also be made via transfer busses D, E, and F located in the normal switchgear room.

The Emergency Switchgear Room would be used to tie the 4160 Vac combustion turbine generators to one of the two Class 1E 4160 Vac buses for each unit. 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. 1(2)-FSG 15, "4160 VAC Generator Connection and Operation," Rev. 0, provides direction for ensuring proper phase rotation before attempting to power equipment from the 4160 Vac combustion turbine generators. Necessary cables for the above connections are also provided from the NSRC.

3.7.4 Accessibility and Lighting

In its FIP, the licensee stated that in order to validate the adequacy of supplemental lighting and the adequacy and practicality of using portable lighting to perform FLEX strategy actions, a lighting study was completed. The licensee further stated that the areas reviewed contain emergency lighting fixtures (10 CFR 50 Appendix "R" lighting) consisting of a battery, battery charger and associated light fixtures. Prior to the depletion of the Appendix "R" lighting, portable battery powered remote area lighting systems (RALS) would be deployed to support the FLEX strategy tasks. These RALS are rechargeable LED lighting systems designed to power the LED lights for a minimum of 7 hours at 6000 lumens or a maximum of 40 hours at 500 lumens. There are no emergency lighting fixtures in the yard in or outside of the protected area to provide necessary lighting in those areas where portable BDB equipment is to be deployed. Therefore, the large portable BDB pumps and diesel generators are outfitted with light plants that are powered from either their respective diesel generators or batteries in order to support connection and operation. In addition to the lights installed on the portable BDB equipment, portable light plants are included in the FLEX strategies. These portable diesel powered light plants can be deployed from the BDB storage building as needed to support nighttime operations. In addition to installed Appendix "R" lighting, the RALS, and the portable light plants, the BDB storage building also includes a stock of flashlights and headband lights to further assist the staff responding to a BDB event during low light conditions.

3.7.5 Access to Protected and Vital Areas

The licensee acknowledges the importance in maintaining the ability to open doors for implementation of the FLEX strategies. For that reason, the FIP states that certain doors will be opened and will remain open. Doors and gates relying on electric power are described to be of concern. The FIP explains that a contingency access plan implemented by security personnel would initiate after losing the electric power, keeping these doors and gates closed. Based on the information provided in its FIP, 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.

3.7.6 Fueling of FLEX Equipment

In FIP Section 2.9.5, the licensee stated that credited FLEX strategy equipment is stored in the fueled condition and fuel tanks are typically sized to hold 24 hours of fuel. Once deployed during a BDBEE, a fuel transfer truck refuels this equipment in the first 24 hours or sooner as required. The licensee plans to draw fuel oil out of any available existing diesel fuel oil tanks on site. The EDG fuel oil day tanks (6 total) contain up to 3300 gallons. Additionally, two EDG underground diesel fuel oil storage tanks each have a capacity of 17,500 gallons. As described in UFSAR Table 15.2-1, Rev. 43, all these tanks, transfer pumps and piping are Seismic Class I and are protected form a design-basis tornado. As described in the FIP, the fuel may be removed from the day tanks via fill and/or drain connections and from the underground tanks through a sample fitting in the top of each tank. The licensee has additional fuel oil storage tanks that are not protected against all applicable hazards, but that could be used if available. The FIP states that the diesel fuel in the fuel oil storage tanks is routinely sampled and tested to assure fuel oil quality is maintained to American Society of Testing and Materials (ASTM) standards. This sampling and testing surveillance program also assures the fuel oil quality is maintained for operation of the station EDGs.

Attachment 11 of FSG-5, “Initial Assessment and FLEX Equipment Staging,” Rev. 1, directs operators to fill the 1000 gallon capacity fuel transfer truck using any of the above mentioned fuel oil tanks. As detailed in the FIP, the fuel transfer truck is stored in the BDB Storage Building, has a capacity of approximately 1,100 gallons and has a self-powered transfer pump. During the audit, the licensee provided calculation, "Surry OIP OI 16 Fuel Consumption Table," Rev. 0, which provides a listing of the BDB diesel equipment and consumption rates. The calculation determined the combine fuel consumption rate of 120 gallons per hour will give Surry approximately 2 weeks of fuel before additional fuel is required from off-site. The diesel fuel consumption calculation did not include diesel fuel requirements for the portable 4160 Vac DGs to be received from the NSRC. More than adequate diesel fuel is available on site for these generators if either the non-robust 210,000 gallon fuel oil storage tank or the 3,000,000 gallon Gravel Neck fuel oil storage is available. If not, provisions for receipt of diesel fuel from offsite sources are in place to facilitate the Phase 3 re-powering strategy with the portable 4160 VAC DGs.

3.7.7 Conclusions

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 guidance, as endorsed, by JLD-ISG-2012-01, and adequately addresses the requirements of the order.

3.8 Considerations in Using Offsite Resources

3.8.1 Surry SAFER Plan

The industry has collectively established the needed off-site capabilities to support FLEX Phase 3 equipment needs via the SAFER Team. The SAFER Team consists of the Pooled Equipment Inventory Company 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 available 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 [Reference 23], 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 – located at the Richmond International Airport) and an alternate (Area D – located at the Wakefield Municipal Airport), which are offsite areas (Area D is within about 25 miles of the plant) utilized for receipt of ground transported or airlifted equipment from the SAFER centers. 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. Use of helicopters to transport equipment from Staging Area C to Staging Area B (at the Surry Power Station) is recognized as a potential need within the Surry SAFER Response Plan and is provided for.

In its FIP, the licensee stated that in the event of a BDBEE and subsequent ELAP/LUHS condition, equipment is moved from an NSRC to a local assembly area established by the SAFER team. From there, equipment can be taken to the Surry site by helicopter if ground transportation is unavailable and staged at one of the two SAFER onsite staging areas. Communications are established between the Surry plant site and the SAFER team via satellite phones and required equipment moved to the site as needed. First arriving equipment is delivered to the site within 24 hours from the initial request. The anticipated order in which equipment is delivered is identified in Surry's SAFER Response Plan; however, the prioritization of equipment is subject to change due to the actual circumstances when the NSRC is contacted. The NRC staff reviewed, in part, the information in the SAFER Response Plan referred to in Surry's FIP. The SAFER plan provides a timeline for implementation and describes the responsibilities between the SAFER team and the site response team. The SAFER Response Plan sets a plan to execute Phase 3 of the FLEX strategies.

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 guidance, as endorsed, by JLD-ISG-2012-01, and adequately addresses 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

Following a BDBEE and subsequent ELAP event at Surry Units 1 and 2, ventilation that provides cooling to occupied areas and areas containing required equipment will be lost. Per the guidance in NEI 12-06, FLEX strategies must be capable of execution under adverse conditions (unavailability of installed plant lighting, ventilation, etc.) expected following a BDB external event resulting in an ELAP/LUHS. The primary concern with regard to ventilation is the heat buildup that occurs when forced ventilation is lost in areas that continue to have heat loads. The key areas identified for all phases of execution of the FLEX strategy activities are the Main Control Room, the Emergency Switchgear Room including the battery rooms, MSVH (SG PORV area and AFW pump room), Containment, Containment Spray Pump House, and the Auxiliary

Building. The licensee evaluated these areas to determine the maximum temperatures expected in specific areas related to FLEX implementation to ensure the environmental conditions remain acceptable for personnel habitability and within equipment qualification limits. With the exception of the SG PORV area in the upper areas of the MSVH, the licensee's calculation showed that temperatures would remain within acceptable limits for all areas with no actions being taken to reduce heat load or to establish either active or passive ventilation (e.g., deployment of portable fans, opening doors, etc.).

During the audit, the NRC staff reviewed calculation ME-0973, "Evaluation of Room Air Temperatures Following Extended Loss of AC Power (ELAP)," Rev. 0 and Addendum A, "Analysis with Doors Open." Calculation ME-0973, Rev. 0 assumes doors remain closed. Calculation ME-0973 uses GOTHIC (Generation of Thermal Hydraulic Information in Containments) version 7.2a, to analyze the heat-up of the following areas, in part, during Phases 1 and 2 of the ELAP event to ensure the loss of forced ventilation and resulting room temperatures would not affect any credited mitigation equipment required for FLEX strategies:

- Main Control Room (MCR)
- Emergency Switchgear Room (ESGR)
- Turbine Driven AFW Pump (TDAFWP) Room
- Main Steam Valve House (MSVH)
- Containment Spray Pumphouse (CSPH)
- Auxiliary Building (AB)

The analyses showed no issues in terms of equipment function for the duration of an ELAP. The calculation assumed a constant outdoor temperature of 90 °F for the duration of the ELAP (i.e. no cooldown at night).

The MCR and ESGR remain below 120 °F when select doors are opened and portable fans are operating. 0-FSG-5, "Initial Assessment and FLEX Equipment Staging," Rev. 1 provides guidance for establishing alternate HVAC cooling and ventilation. The ESGR is calculated to reach 120 °F in 12 hours if ventilation was lost and no actions were taken and if all electrical equipment were functioning (conservative estimate). The battery room temperature is expected to be similar to the ESGR. Normal ventilation is expected to be restored when 480 V FLEX DGs are operational. If 480V FLEX DGs are not available, procedures direct the operators to prop open doors and install portable fans in doorways.

Calculation ME-0973 determined the TDAFWP area temperature (27' elevation) is expected to remain below 120°F. The calculation also conservatively assumed that at least one motor driven auxiliary feedwater pump (MDAFWP) was operating. The TDAFWP Room was previously evaluated for Station Blackout (SBO) in calculations 01039 101-USB-95, Revision 1, "SBO Loss of Ventilation Temperature Transients" and ME-0800, "GOTHIC MSVH Loss of Ventilation," Revision 0. Calculation 01039101-USB-95 assumes AFW pump house doors and damper are manually opened within one hour after a SBO. Specific doors and dampers are identified in the calculation assumptions. Based on these calculations, the licensee expects the TDAFWP Room to remain below 120 °F following an ELAP.

However, the Surry SBO coping strategy assumes starting a SBO diesel and operating a MDAFWP instead of the TDAFWP. Calculation 01039101-USB-95 evaluated the TDAFWP operating. However, the calculation assumed the heat loss from the operating TDAFWP was equal to a percentage of the heat loss from other piping in the Main Steam Valve House. During the audit, NRC staff questioned the use of a SBO calculation which used a motor driven pump that would not be available during an ELAP. In addition the NRC staff questioned using the heat loss from other piping in the room as the heat loss from the operating TDAFWP. The licensee indicated the evaluation assumed two MDAFWPs operating along with the TDAFWP. In addition, the licensee described the size and lengths of main steam and feedwater piping used to determine the TDAFWP heat loss. The NRC staff agrees that heat loss from the combination of two MDAFWPs and one TDAFWP operating is conservative for an ELAP. The licensee described the louvered opening near the pumps (96” x 54”) and that the upper area of the MSVH connects to the outdoor environment through existing openings. During the on-site audit, the NRC staff performed a walkdown of the TDAFW pump room and the ventilation path that will be established. The licensee’s ventilation strategy for the TDAFW pump room will rely on either louvers or a series of doors opened on the 27' level as a ventilation inlet and a door to the roof located near the SG safety valves as an exhaust. Procedure 0-FSG-05 provides guidance for establishing ventilation. The NRC staff finds that given the large grade level opening, large permanent openings at the top of the MSVH, along with intervening floors made of grating, there will be sufficient stack effect to maintain acceptable temperatures near the TDAFWP.

Main Control Room

For the MCR, the licensee’s calculation (ME-0973) showed that the temperature will remain below 120 °F with no credit taken for opening doors.

Based on temperatures remaining 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,” Rev. 1, for electronic equipment to be able to survive indefinitely), the NRC staff finds that the equipment in the MCR will not be adversely impacted by the loss of ventilation as a result of an ELAP event.

ESGR and Battery Rooms

For the ESGR, the licensee’s calculation (ME-0973) showed that the temperature will remain below 120 °F with no credit taken for opening doors.

Based on temperatures remaining 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,” Rev. 1, for electronic equipment to be able to survive indefinitely), the NRC staff finds that the equipment in the ESGR will not be adversely impacted by the loss of ventilation as a result of an ELAP event.

The licensee typically maintains ambient temperature in the Surry safety-related battery rooms between 70 °F and 80 °F. The MCR/ESGR normal ventilation system supplies 250 cfm of conditioned air to each safety-related battery room, and each safety-related battery room is exhausted by the MCR/ESGR exhaust fan. The concrete walls, floors and ceiling in the safety-related battery rooms function as a large heat sink following loss of ventilation. Procedure 0-FSG-5 directs plant operators to address ventilation concerns in the MCR/ESGR and safety-related battery rooms shortly after the onset of an ELAP. Specifically, 0-FSG-5 directs plant operators to open equipment room and cabinets doors, and provide temporary fans and ducting, as necessary, in the MCR and ESGR. Plant operators would establish battery room ventilation using procedures 1(2)-FSG-4.

Heat loads in the MCR/ESGR and safety-related battery rooms following an ELAP are minimal (lighting, dc-powered loads) compared to normal operating loads such as large transformers and breakers, battery chargers, and motors. Additionally, following an ELAP, plant operators would strip loads from the station's safety-related batteries to prolong the life of the batteries. The heat load from batteries during discharge and charging is a function of the internal resistance and the square of the current. Since load shedding is expected to be completed approximately 1 hour and 15 minutes from the onset of an ELAP event, the heat generated in the battery will be minimized due to the lower current draw, and the rate of release into the room will be slow due to the large mass of electrolyte. Furthermore, the heat sinks in the ESGRs and battery rooms minimize the rate of temperature increase or decrease in the battery room, regardless of the outside ambient temperature.

Based on the above, the NRC staff finds that the licensee's ventilation strategy, in combination with the effect of the heat sinks in the ESGRs (steel, concrete) and the open doorways to the Turbine Building and other rooms, will maintain the battery room temperature below the maximum temperature limit (120 °F) of the batteries, as specified by the battery manufacturer (Enersys). Therefore, the NRC staff finds that the Surry safety-related batteries should perform their required functions at the expected temperatures as a result of loss of ventilation during an ELAP event.

MSVH (SG PORV area and AFW pump room)

According to the licensee's calculation (ME-0973), the AFW pump room room (MSVH 27' EL) will remain below 120 °F. Based on temperatures remaining 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," Rev. 1, for electronic equipment to be able to survive indefinitely), the NRC staff finds that the equipment in the AFW pump room will not be adversely impacted by the loss of ventilation as a result of an ELAP event.

In the case of the upper level of the MSVH, the licensee would initiate a ventilation strategy within 2 hours of an ELAP event to ensure that the temperatures remain within the acceptable range for equipment and personnel habitability. The licensee's ventilation strategy includes opening an external door in the MSVH, which would allow outside air to flow up through the MSVH ventilation opening in the top of the building.

The temperatures expected in the upper level of the MSVH for local operation of the SG PORV are similar to conditions experienced during normal station operations, testing, and maintenance. Therefore, actions performed for FLEX activities are essentially the same as those performed for the current site procedure ECA-0.0 which addresses local operation of the SG PORVs.

Since the licensee is crediting local, manual actions to operate the SG PORVs, the NRC staff did not review the affect of the expected temperatures during an ELAP on electrical equipment in the area.

Containment

See Section 3.4.4.4 of this SE for the NRC staff's evaluation of the licensee's mitigating strategy for maintaining containment temperature within design limit of credited instrumentation and equipment.

Containment Spray Pump House

According to the licensee's calculation (ME-0973 Addendum A), the Containment Spray Pump House is expected to remain below 120 °F. Based on temperatures remaining within equipment limits and/or quickly dropping below 120 °F (the temperature limit, as identified in NUMARC-87-00 for electronic equipment to be able to survive indefinitely), the NRC staff finds that the equipment in the Containment Spray Pump House will not be adversely impacted by the loss of ventilation as a result of an ELAP event.

Auxiliary Building

According to the licensee's calculation (ME-0973 Addendum A), the Auxiliary Building is expected to remain below 120 °F. Based on temperatures remaining below design limits and/or 120 °F (the temperature limit, as identified in NUMARC-87-00 for electronic equipment to be able to survive indefinitely), the NRC staff finds that the equipment in the Auxiliary Building will not be adversely impacted by the loss of ventilation as a result of an ELAP event.

3.9.1.2 Loss of Heating

The methods of dealing with the effects of extreme cold on equipment are addressed in procedures (ETE Section 14) and the availability of heaters is addressed. Several references to portable heating equipment are made in the ETE and FIP. For example, Section 14.1.2 of the FLEX ETE-CPR-2012-0011 states: "Additionally, portable heating equipment is stored in the BDB Storage Building for additional low temperature mitigation, as needed."

With regard to personnel habitability in rooms, the answer would be the same as habitability outside. ETE-CPR-2012-0011, Table 1, line item #'s 135, 136, and 137, indicate that cold weather gear is available to the operators to help deal with the effects of extreme cold weather. If operators can dress warm enough to go outside, they would be OK in any room. Typically, the concern is heat sources in rooms, therefore, "typically" it would be warmer in a room than the outside temperature. If not, however, heaters are available, as needed.

With regard to loss of heating in the Surry 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. Therefore, reaching the minimum battery temperature limit (60 °F) is not expected.

Based on the above, the NRC staff finds that Surry safety-related batteries should perform their required functions if heating is lost during an ELAP event and that habitability should not be compromised.

3.9.1.3 Hydrogen Gas Control in Vital Battery Rooms

An additional ventilation concern that is applicable to Phases 2 and 3, is the potential buildup of hydrogen in the battery rooms 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 order to prevent a buildup of hydrogen in the battery rooms, the licensee's procedures direct plant operators to open the battery room doors and establish ventilation using pre-staged portable fans (120 Vac power supply must be made available in the area of the battery rooms in order to power the fans) to disperse the off-gassing hydrogen to a much larger area in order to prevent any significant hydrogen accumulation. Procedure 0-FSG-05 provides guidance for opening doors and deploying portable fans after a loss of ventilation and cooling due to ELAP.

Based on its review, the NRC staff finds that the licensee's evaluation demonstrated that hydrogen accumulation in the Class 1E station 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 open the battery room doors and place portable fans in service when the battery chargers are repowered during Phases 2 and 3.

3.9.2 Personnel Habitability

Per the August 2014 updated OIP Section F5 for Safety Functions Support (Ventilation), with the exception of SG PORV area in the upper portion of the MSVH, calculations indicate temperatures remain within acceptable limits with no actions taken to reduce heat loads. For the MSVH upper area (Steam Generator PORV area) opening doors will provide sufficient natural ventilation. No additional actions are anticipated for Phase 3.

TDAFWP Room (MSVH 27' level) is expected to remain below 120 °F following an ELAP since the majority of heat sources in this area will not be operating. The BOP staff completed a walkdown of the TDAFW pump room and ventilation path that will be established. The licensee will rely on either louvers or a series of doors open on the MSVH 27' level as a ventilation inlet and a door to the roof located near the SG PORVs as an exhaust.

3.9.2.1 Main Control Room

The MCR remains below 120 degrees F when doors are opened and portable fans are operating (controlled by 0-FSG-5, "Initial Assessment and FLEX Equipment Staging,"). 0-FSG-5, Step 11 provides guidance for establishing alternate HVAC cooling and ventilation. Normal ventilation is expected to be restored when 480 V FLEX DGs are operational. If 480 V FLEX DGs are not available, procedures direct the operators to prop open doors and install portable fans in doorways.

3.9.2.2 Spent Fuel Pool Area

See Section 3.3.4.1.1 above for the detailed discussion of ventilation and habitability considerations in the SFP Area. In general, the licensee plans to establish Fuel Building ventilation so that boiling of the SFP affects does not affect habitability. The licensee also has the ability to add water to the SFP from the installed SFP cooling piping without accessing the refueling floor.

3.9.2.3 Other Plant Areas

The ESGR remains below 120 °F when doors are opened and portable fans are operating (controlled by 0-FSG-5, Rev. 1). Procedure 0-FSG-5 provides guidance for establishing alternate HVAC cooling and ventilation. The ESGR would reach 120 °F in 12 hours if ventilation was lost and no actions were taken and if all electrical equipment were functioning (conservative estimate). Battery room temperature is expected to be similar to ESGR. Normal ventilation is expected to be restored when 480 V FLEX DGs are operational. If the 480 V FLEX DGs are not available, procedures direct the operators to prop open doors and install portable fans in doorways. Ventilation to upper level of the MSVH is identified as needing to be established within 2 hours to allow access to instrument air valves to the steam generator power operated valves.

3.9.3 Conclusions

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 guidance, as endorsed, by JLD-ISG-2012-01 and should adequately address the requirements of the order.

3.10 Water Sources

In its FIP, the licensee provided a table listing in order of preferred use; the onsite water sources available to provide cooling water to the SGs, their capacities, and their availability following a BDB event. As noted in the table, three water sources would survive all applicable hazards and are credited for use in the FLEX strategies - ECST (Phase 1), ECMT (Phase 1), and the discharge canal (Phase 2 and 3).

The onsite water sources have a wide range of associated chemical compositions. Therefore, extended operation with the addition of these various onsite water sources to the SGs has been evaluated for impact on long-term SG performance (heat transfer) and SG material (e.g., tube) degradation. The evaluation provides guidance for duration that the various onsite water sources can be used for core cooling/decay heat removal. Use of the available clean water sources, tanks and condensers, are limited by only their quantity. The water supply from the James River and the condensate polishing (CP) settling pond is essentially unlimited by quantity but is limited in quality and the concentration of total suspended solids (TSS). The SG design corrosion limit corresponds to operating temperatures and pressures and is a conservative approach to the evaluation. Exceeding the expected time to reach the SG design corrosion limit would have an insignificant impact on the ability of the SG to remove core decay heat from the RCS due to the significantly lower than design SG temperature/pressure conditions. However, continued corrosion could become a tube integrity concern. Reaching the limiting SG precipitation levels could potentially impact/reduce SG heat transfer capability. The accumulation of precipitates in the SG may eventually block flow through the SG. Precipitation accumulation is conservatively evaluated using a TSS value of 500 parts per million (ppm).

The evaluation shows that the water from CP settling pond could be used for approximately 21 days after ECST depletion before the SG design corrosion limit would be expected to be reached. If a conservative TSS level of 500 ppm is assumed for the CP settling pond, the limiting SG precipitation level would be expected to be reached about 10 days after ECST depletion. Water from the onsite wells (which provide makeup to the fire protection tanks) could be used for about 16 days after ECST depletion before the SG precipitation limit would be expected to be reached, however, inventory from the onsite well would be limited to approximately 1 week.

The evaluation shows that water from the James River could cause pitting of the SG tubes but is further limited by precipitation concerns to approximately 50 - 60 hours. On this basis, water from James River should only be considered for use in the SGs as a last resort.

The results of the water quality evaluation show that the credited, fully protected, on site water sources provide an adequate AFW supply source for a much longer time than would be required for the delivery and deployment of the Phase 3 NSRC reverse osmosis/ion exchange equipment to remove impurities from the onsite natural water sources. The reverse osmosis/ion exchange units have a capacity of up to 300 gpm. Once the reverse osmosis/ion exchange equipment is in operation, the onsite water sources provide for an indefinite supply of purified water.

3.10.1 Steam Generator Make-Up

Phase 1

In the FIP, Section 2.3.10.4 states that the ECST (one per unit) followed by the ECMT (one per unit) provides the main source of water for plant cool-down at the initial onset of the ELAP event and into Phase 2. In the UFSAR, Section 10.3.5.3 states the ECST is a tornado and missile protected tank with a capacity of 110,000 gallons and is maintained above 96,000 gallons during normal operation. During the audit, the licensee provided calculation ME-0963, "NPSH Analysis for the TDAFW pump taking suction from the Emergency Condensate Makeup Tank (ECMT)," Rev. 0, which calculated the minimum net positive suction head (NPSH) required for to use the ECMT without the normally operating booster pumps which would not be functional during an ELAP. The calculation determined that at the required flow rate of 350 gpm, the ECMT would provide adequate NPSH until the approximate level of 22 ft in the tank, which equates to a minimum usable volume of 72,000 gallons. UFSAR Table 15.2-1 indicates that both the ECST and ECMT are Seismic Class I tanks that are protected against a design basis tornado. If implemented appropriately and consistent with the FIP, the licensee should have a water source available during the Phase 1 core cooling strategies for SG inventory makeup. In addition, the licensee's strategy should provide sufficient time for operators to deploy and stage Phase 2 FLEX equipment. The FIP Table 3, shows that the ECST and the ECMT have sufficient water inventory for approximately 14.2 hours into the ELAP event.

Phase 2

The licensee indicated that it will preferentially use any surviving, non-seismic, clean water tanks to provide makeup to the ECST using diesel driven transfer pumps or air driven transfer pumps, hoses and installed FLEX connections. However, if none of these non-robust water sources are available, the licensee plans to use either the Condensate Polishing Settling Pond or the James River via the discharge canal. The BDB High Capacity pump will be staged by either water source with a suction hose deployed directly into the available water source. As discussed earlier, the BDB High Capacity pump will discharge to the ECST, directly to the suction of the BDB AFW pump, and/or to the SFP. The discharge canal is essentially an unlimited water source, however, since it is brackish water, it is the least preferred alternate AFW supply source. There are no damns downstream of the James River that impact water level. If implemented appropriately and consistent with the FIP, the licensee should have an adequate source of water available during the Phase 2 core cooling and have sufficient time for the arrival of off-site equipment from the NSRC.

Phase 3

In the FIP, Section 2.3.3 indicates that a mobile water purification system will be supplied by the NSRC to purify the James River or other raw water sources.

3.10.2 Reactor Coolant System Make-Up

Phase 1

In its FIP, the licensee stated that in general, the FLEX strategy for RCS inventory control/reactivity management relies on RCP seal leakage being sufficiently low for initial control of RCS inventory, isolation of the RCS as directed by the emergency procedure, and cooldown limitations to limit reactivity addition. With these controls in place, no RCS makeup or boration is required for the first 17 hours of an ELAP/LUHS event, at which point reflux cooling is conservatively assumed to occur in the RCS. The RCS makeup and boration will be initiated within 16 hours of the event, during Phase 2, to prevent the entry into reflux cooling. The licensee indicated in its FIP that the emergency procedure also directs the operators to minimize RCS inventory loss through potential RCS letdown paths by closing or verifying closed RCS letdown isolation valves, pressurizer PORVs, excess letdown valves, RCS sample valves, loop drain valves, reactor vent valves, pressurizer vent valves, and RCP seal injection/return valves.

Phase 2

The FIP stated during Phase 2 the RWST will be the preferred borated water source. Each unit is equipped with one RWST located at grade level just outside of its respective safeguards building. As described in the FIP, the tanks are stainless steel, safety-related, seismically qualified storage tanks (see UFSAR Table 15.2-1), but are not protected from high wind/tornado generated missiles. During normal operations each operating unit's RWST borated water volume is maintained at greater than 370,000 gallons at a boron concentration between 2300 and 2500 ppm. The RWST is the preferred borated water source for the RCS Injection strategies.

In the event that both RWSTs are unavailable or become depleted, portable boric acid mixing tanks are available to provide a suction source for the BDB RCS injection pumps. The boric acid mixing tanks are stored in the BDB Storage Building. Dilution water is added to the mixing tank by either a portable transfer pump, the BDB AFW pump, or from the BDB high capacity pump header. Bags of powdered boric acid are mixed with dilution water to achieve the proper concentration for maintaining adequate shutdown margin while making up RCS inventory. Each tank is equipped with an agitator to facilitate mixing of the boric acid which is continued throughout the injection.

Phase 3

In the FIP, Section 2.3.3 indicates that a mobile water purification system will be supplied by the NSRC to purify the James River or other raw water sources.

3.10.3 Spent Fuel Pool Make-Up

The SFP is a common pool designed for both Unit Nos. 1 and 2. The licensee stated in its FIP that any water source available is acceptable for use as makeup to the SFP, however, the primary source would be from the CP settling pond or James River via the BDB High Capacity pump. Both water sources are discussed in Section 3.10.1.

3.10.4 Containment Cooling

The licensee indicated in its FIP, that containment cooling is not needed during Phase 1 and 2. For Phase 3, offsite equipment is used to power various station pumps. If service water is not available from the circulating water intake canal, then low pressure/high flow diesel-driven pumps are used to provide flow to existing site heat exchangers to facilitate heat removal from the containment atmosphere. Water to the SW system and to the CC heat exchangers is typically supplied from CW via the intake canal by gravity feed through the CC heat exchangers. If adequate water volume remains in the intake canal following a BDB event, design-basis SW flow to each unit's CC heat exchanger can be established by opening the appropriate motor operated valves in the SW system. If the CW intake canal does not have sufficient water supply, water can be added to the intake canal by the diesel-driven emergency service water pumps or by deploying a low pressure/high flow pump from the NSRC to pump water from the James River into the intake canal. If the CW intake canal is not available, then water to the SW system/CC heat exchangers is established by taking suction from the discharge canal using a low pressure/high flow pump from the NSRC and connecting to the service water supply header using a blind flange adapter available in the BDB storage building.

3.10.5 Conclusions

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 guidance, 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 51 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. On September 18, 2013, NEI submitted to the NRC a position paper entitled "Shutdown/Refueling Modes" [Reference 37], which described methods to ensure plant safety in those shutdown modes. By letter dated September 30, 2013 [Reference 38], the NRC staff endorsed this position paper as a means of meeting the requirements of the order.

The position paper 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. The NRC staff concludes that the position paper provides an acceptable approach for demonstrating that the licensees are capable of implementing mitigating strategies in shutdown and refueling modes of operation. The FIP states that the licensee plans to follow the guidance in this position paper. During the audit process, the NRC staff observed that the licensee had made progress in implementing this position paper.

Based on the information above, 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 adequately addresses the requirements of the order.

3.12 Procedures and Training

In its FIP, the licensee stated that the FSGs provide guidance to be employed for a variety of conditions. Criteria for entry into FSGs ensures that FLEX strategies are used only as directed for BDB external event conditions. When equipment is needed to supplement EOPs or abnormal operating procedures (AOPs), the EOP or AOP directs the entry into and exit from the appropriate FSG procedure. FLEX support guidelines have been developed in accordance with PWROG guidelines. The FIP states that the FSGs provide instructions for implementing available, preplanned FLEX strategies to accomplish specific tasks in the EOPs or AOPs. The FSGs are used to supplement (not replace) the existing procedure structure that establishes command and control for the event. The licensee states that procedural interfaces have been incorporated into 1/2-ECA-0.0 to the extent necessary to include appropriate reference to FSGs and provide command and control for the ELAP. Also, the FIP states that procedural interfaces have been incorporated into the following procedures to include appropriate reference to FSGs: Procedures 0-AP-22.02, “Malfunction of Spent Fuel System,” and1/2-AP-27.00, “Loss of Decay Heat Removal Capability.” Additionally, a new abnormal procedure, 1/2-AP-10.27, “Loss of All AC Power while on RHR,” was prepared to provide the command and control function for the ELAP while on RHR. Procedure 1/2-ECA-0.0 does not apply in this operating mode.

In its FIP, the licensee stated that Dominion’s nuclear training program has been revised to assure personnel proficiency in utilizing FSGs and associated BDB equipment for the mitigation of BDBEEs is adequate and maintained. The licensee states to have developed and implemented programs and controls in accordance with the systematic approach to training (SAT) process. The licensee also stated that initial training is in accordance with Section 11.6 of NEI 12-06, ANSI/ANS 3.5, “Nuclear Power Plant Simulators for use in Operator Training”, certification of simulator fidelity is considered to be sufficient for the initial stages of the BDB external event scenario. Full scope simulator models have not been upgraded to accommodate FLEX training or drills. Where appropriate, integrated FLEX drills are organized on a team or crew basis and conducted periodically; with all time-sensitive actions are evaluated over a period of not more than 8 years. It is not required to connect/operate permanently installed equipment during these drills.

During the audit, the staff was able to see procedures and training documents. Based on the review of the license’s submittal this review, the NRC staff concludes that the licensee has developed guidance that should adequately address FLEX procedures and training expectations described in NEI 12-06 Section 11. The procedures have been issued and a training program has been established and will be that, if implemented appropriately, should maintained be in accordance with NEI 12-06, Section 11.6.

3.13 Maintenance and Testing of FLEX Equipment

As a generic issue, NEI submitted a letter to the NRC dated October 3, 2013 [Reference 39], which included Electric Power Research Institute (EPRI) Technical Report 3002000623, "Nuclear Maintenance Applications Center”: Preventive Maintenance Basis for FLEX Equipment." By letter dated October 7, 2013 [Reference 40], 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.

In its FIP, the licensee stated that factory acceptance testing and site acceptance testing, was conducted to ensure the portable FLEX equipment can perform its required FLEX strategy design functions. Factory acceptance testing was done to verify that the portable equipment performance conformed to the manufacturers rating for the equipment as specified in the purchase order. Also, vendor test documentation was verified as part of the receipt inspection process for each of the affected pieces of equipment and included in the applicable vendor technical manuals. Site acceptance testing confirmed factory acceptance testing to ensure portable FLEX equipment delivered to the site performed in accordance with the FLEX strategy functional design requirements. Portable BDB equipment that directly performs a FLEX mitigation strategy for the core cooling, containment, or SFP cooling is subject to periodic maintenance and testing in accordance with NEI 12-06 and Institute of Nuclear Power Operations AP 913, “Equipment Reliability Process,” to verify proper function. The licensee also stated that preventive maintenance will be provided for other FLEX support equipment.

The FIP states that the licensee uses EPRI’s Preventive Maintenance (PM) Basis for FLEX Equipment guidance and maintenance templates for the major FLEX equipment including the portable diesel pumps and generators. Corresponding maintenance strategies were developed and documented. The performance of the PMs and test procedures are controlled through the site work order process. It is stated that performance verification of FLEX equipment is scheduled and performed as part of the PM process. The licensee stated that a fleet procedure was established to reduce the risk for unavailability of equipment and applicable connections that directly perform a FLEX mitigation strategy for core cooling, containment, and SFP cooling. Maintenance/risk guidance were described to conform to the guidance of NEI 12-06.

As previously discussed in this SE, the 10 CFR 50.54(hh)(2) pump is used as the N+1 pump for the FLEX high capacity pump function and is considered an alternative approach for stored BDB equipment. The alternate maintenance outage times are discussed in Section 3.14 below
After reviewing the licensee’s programs, the NRC staff finds that the licensee has developed guidance for equipment maintenance and testing activities associated with FLEX equipment that, if implemented as described, should be in accordance with NEI 12-06, Section 11.5. Also, the staff finds that the alternate approach involving the 10 CFR 50.54(hh)(2) high capacity pump seems to meet the intent of NEI 12-06 as approved by the NRC (refer to Section 3.14.1).

3.14 Alternatives to NEI 12-06, Revision 0

3.14.1 Use of the 10 CFR 50.54(hh)(2) Pump as a High Capacity FLEX Pump

In its FIP, the licensee took an alternative approach to meet the N+1 requirement for the BDB high capacity pump. In its FIP, the licensee stated that the 50.54(hh)(2) high capacity pump can meet the flow requirements for both the FLEX core cooling and SFP cooling strategies that credit the BDB high capacity pump and serves to meet the N+ 1 requirement. The 50.54(hh)(2) high capacity pump is stored in the emergency response building on site, which is reasonably protected from flooding, extreme heat, and extreme cold hazards. The emergency response building does not meet the requirements of NEI 12-06 Sections 7.3.1 and 5.3.1 because it is not fully protected against seismic, high wind/tornado missile, and hurricane events, respectively. Therefore, the storage arrangements for the 50.54(hh)(2) pump represent an alternate approach to the requirements of NEI 12-06, Sections 5.3.1, 7.3.1, and 11.3.3.

As stated in its FIP, Dominion has implemented compensatory actions to support this alternative approach for stored BDB equipment. The unavailability requirements for FLEX equipment are prescribed by Dominion Fleet procedure ADM-CM-AA-BDB-102 and include additional requirements to address the storage capability of FLEX equipment that is not fully protected. These additional requirements are as follows:

> The required FLEX equipment may be unavailable for 90 days provided that the site FLEX capability (N) is met. If the site FLEX (N) capability is met but not fully protected for the site's applicable hazards, the allowed unavailability is reduced to 45 days.

Additionally, ADM-CM-AA-BDB-102 provides appropriate guidance for reasonable protection during forecast adverse external conditions as follows:

> If FLEX equipment is likely to be unavailable during forecast site-specific external events (e.g., hurricane), then appropriate compensatory measures should be taken to restore equivalent capability in advance of the event.

Dominion's Abnormal Procedure, 0-AP-37.01, "Abnormal Environmental Weather Conditions," accommodates this requirement as it invokes an evaluation of the availability of BDB equipment, which includes the 50.54(hh)(2) pumps, upon approaching severe weather.

These actions are intended to limit the potential vulnerability of the 50.54(hh)(2) pump. Therefore, the current on-site FLEX equipment storage configuration in conjunction with the procedural FLEX equipment unavailability requirements provide ways to reduce the risk of losing the site FLEX (N) capability related to the 50.54(hh)(2) pump. For these reasons, the staff founds that, if implemented accordingly, the proposed alternative to use the 50.54(hh)(2) pump as the high capacity pump for both FLEX core cooling and SFP cooling strategies, and its storage in the emergency response building, are acceptable alternatives to the NEI 12-06 guidance.

3.14.2 Reduced Set of Hoses and Cables As Backup Equipment

In its FIP, the licensee took an alternative approach to the NEI 12-06 guidance for hoses and cables. In NEI 12-06, Section 3.2.2 states that in order to assure reliability and availability of the FLEX equipment required to meet these capabilities, 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. Thus, a single-unit site would nominally have at least two portable pumps, two sets of portable ac/dc power supplies, two sets of hoses and cables, etc. NEI on behalf of the industry submitted a letter to the NRC [Reference 46] proposing an alternative regarding the quantity of spare hoses and cables to be stored on site. The alternative proposed was that that either a) 10 percent additional lengths of each type and size of hoses and cabling necessary for the N capability plus at least one spare of the longest single section/length of hose and cable be provided or b) that spare cabling and hose of sufficient length and sizing to replace the single longest run needed to support any FLEX strategy. The licensee has committed to following the NEI proposal. By letter dated May 18, 2015 [Reference 47], the NRC agreed that the alternative approach is reasonable, but the licensees may need to provide additional justification regarding the acceptability of various cable and hose lengths with respect to voltage drops, and fluid flow resistance. The NRC staff approves this alternative as being an acceptable method of compliance with the order.

In conclusion, the NRC staff finds that although the guidance of NEI 12-06 has not been met, if these alternatives are implemented as described by the licensee, the requirements of the order should be met.

3.15 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, will adequately address the requirements of Order EA-12-049.

4.0 TECHNICAL EVALUATION OF ORDER EA-12-051

By letter dated February 28, 2013 [Reference 24], the licensee submitted its OIP for Surry in response to Order EA-12-051. By e-mail dated October 4, 2013 [Reference 25] the NRC staff sent a request for additional information (RAI) to the licensee. The licensee provided a response to the RAI by letter dated August 8, 2013 2013 [Reference 26]. By letter dated November 1, 2013 [Reference 27], the NRC staff issued an Interim Staff Evaluation and RAI to the licensee. By letter dated April 14, 2015 [Reference 17], the NRC issued an audit report on the licensee's progress.

By letters dated August 23, 2013 [Reference 28], February 27, 2014 [Reference 29], August 26, 2014 [Reference 30], and March 2, 2015 [Reference 31], 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 SFP level instrumentation which will function following a BDBEE, including modifications necessary to support this implementation, pursuant to Order EA-12-051. By letter dated July 20, 2015 [Reference 33] the licensee reported that full compliance with the requirements of Order EA-12-051 was achieved.

The licensee has installed a SFP level instrumentation system designed by Westinghouse. The NRC staff reviewed the vendor's SFP level instrumentation system design specifications, calculations and analyses, test plans, and test reports. The staff issued an audit report on August 18, 2014 [Reference 34].

The staff performed an onsite audit 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 April 14, 2015 [Reference 17], the NRC issued an audit report on the licensee's progress. Refer to section 2.2 above for the regulatory background for this section.

4.1 Levels of Required Monitoring

Attachment 2 of Order EA-12-051 states in part:

All licensees identified in Attachment 1 to this 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 [Level 1], (2) level that is adequate to provide substantial radiation shielding for a person standing on the SFP operating deck [Level 2], and (3) level where fuel remains covered and actions to implement make-up water addition should no longer be deferred [Level 3].

In its OIP, the licensee stated that Level 1 is the indicated level on either the primary or back-up instrument channel of greater than approximate elevation of 42 feet (ft.) 2 inches (in.) based on the elevation at which the top of the SFP cooling pump suction lines penetrate the pool walls. Level 2 is the indicated level on either the primary or back-up instrument channel of greater than approximately elevation 31 ft. 3 in., which corresponds approximately 10 ft. above the top of the SFP fuel rack. Level 3 is the indicated level on either the primary or back-up instrument channel of greater than approximate elevation of 21 ft. 3 in. which is one foot above the highest point of any fuel rack seated in the SFP.

By email dated July 11, 2013 [Reference 25], the NRC staff sent an RAI to the licensee. In RAI-1 the staff inquired, in part, how the location of Level 1 identified in the OIP represent the higher of the two points described in NEI 12-02 guidance. The licensee provided a response by letter dated August 8, 2013 [Reference 26], which it stated, in part, that in the Surry OIP, the Level 1 elevation represents the higher of the two points identified in NEI 12-02. The Surry SFP Level Instrumentation at level 1 measures the water level required to support operation of the normal fuel pool cooling system. As stated in the OIP, this level is the indicated level on either the primary or back-up instrumentation of greater than elevation of 42 ft. 2 in. plus the accuracy of the SFP level instrument channel. This level is based on the elevation at which the top of the SFP cooling pump suction lines penetrate the pool walls. For the lower point, a calculation is being performed to verify that adequate water level is available to support the NPSH of the SFP cooling pumps.

In its letter dated August 23, 2013 [Reference 28], the licensee stated, in part, that adequate water level is available to support NPSH has been completed and independently reviewed. Results of the calculation confirm the Level 1 value of 42 ft. 2 in. is higher than the minimum NPSH level of 40 ft. 4 in. In the this letter, the licensee also provided a sketch showing the approximate location of the elevations identified as Level 1, 2 and 3, the top of the tallest fuel storage rack and SFP instrumentation span. In a letter dated July 20, 2015, the licensee stated that Level 2 is approximately 10 ft. above the top of the fuel racks. It is the indicated level of greater than elevation 31 ft. 4 in. plus the accuracy of the SFP level instrumentation channel. This water level ensures there is sufficient depth such that necessary operations in the vicinity of the SFP can be completed without significant dose consequences. The licensee also stated that Level 3 corresponds to one foot above the highest point of any fuel rack seated in the SFP. It is the indicated level of elevation 22 ft. 4 in., which is one foot above the highest point of any fuel rack in the SFP based on field measurements (Elevation 21 ft. 4 in.), plus the accuracy of the SFP level instrumentation channel. This is the water level at which the spent fuel remains covered. The NRC staff found the licensee's response acceptable. The staff found that Level 1 is adequate for normal SFP cooling system operation; it is also 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 spent fuel pool can be completed without significant dose consequences. Level 3 is 1 foot above the highest point of any fuel storage rack seated in the spent fuel pool. At this level, fuel remains covered.

On July 27, 2016, the licensee provided supplement information [Reference 32] to correct the SFP instrumentation Level 1 value after Calculation MISC-11798 was subsequently revised (Rev. 1) to reflect the presence of an inlet weir/waterbox. The revision of Calculation MISC-11798 redefined the Level 1 value of 42 ft. 2 inches to 44 ft.11 inches. To accommodate the instrument accuracy, the licensee added 3 inches to the new Level 1 value, raising it up to 45 ft. 2 inches. The new change did not change the staff's conclusion on the acceptability of the SFP instrumentation level values.

Based on the discussion above, the NRC staff finds that the licensee's proposed Levels 1, 2, and 3 are 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. Refer to Section 2.2 above for the requirements of the order in regards to the design features. 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 back-up channels will use a fixed instrument providing continuous level measurement over the entire range. The measured range will be from approximately an elevation of 45 ft. 10 in. to elevation 21 ft. 3 in. for a total indicated range of approximately 24 ft. 7 in. In its letter dated August 8, 2013, the licensee provided a sketch showing the approximate location of the elevation identified as Levels 1, 2, and 3, the top of the tallest fuel storage rack and SFP instrumentation span. This sketch shows the SFPLI span would be 24 ft. 5 in. In its letter dated July 20, 2015 [Reference 33], the licensee stated that the Westinghouse SFPLI system uses Guided Wave Radar (GWR) technology. The GWR level measurement instruments work based on the Time Domain Reflectometry (TDR) principle. The level measurement instrumentation sends low intensity microwave electromagnetic pulses along a flexible conductor where pulses travel at the speed of light. When the pulses reach the surface of the medium to be measured, a portion of the signals is reflected back to the electronics. The electronics calculate the SFP water level by measuring the time elapsed between the initial pulse and the reflected one. One complete measurement cycle is made up of several thousand pulses. The measurement cycles are made two times per second and processed by special filtering techniques before generating a current output proportional to the SFP water level. The current output of the electronics is representative of the measured level. The current output of the electronics is representative of the measured level and converted for use in displaying level information. 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 finds that the number of channels and measurement range for its SFP, is 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 on the west wall of the SFP and the back-up instrument channel level sensing component will be located in the southeast corner of the SFP. In addition, the licensee stated that the primary and back-up channel level sensor probes will be installed on opposite sides of the SFP to maintain adequate channel separation. In the conceptual design, the SFP probes bolt to a triangular mounting plate for installation at the corner of the SFP or a rectangular plat for mounting at the side of the SFP.

In its letter dated August 8, 2013 [Reference 26], the licensee stated that the final locations of the level sensor, electronics and display units have not yet been determined. The licensee also stated that the conceptual design places the sensor probes in the Fuel Building, the signal conditioning electronics in the Auxiliary Building and the read-out/display units in the Cable Spreading room within the Service Building. Additionally, in this letter, the licensee stated that the final system component locations will be available upon completion of the final design, scheduled for December 2013, and the licensee would forward this information to the NRC staff during the subsequent scheduled status update.

By email dated July 11, 2013 [Reference 25], the staff sent an RAI to the licensee. This RAI was carried over to the ISE the staff sent to the licensee by the letter dated November 1, 2013 [Reference 27] as RAI-1. In RAI-1, the staff requested the licensee to provide a clearly labeled sketch or marked-up plant drawing of the plan view of the SFP area, depicting the SFP inside dimensions, the planned locations/placement of the primary and back-up SFP level sensor, and the proposed routing of the cables that will extend from these sensors toward the location of the read-out/display device. In its letter dated March 2, 2015 [Reference 31], the licensee provided a plan view sketch of the Surry SFP area. The sketch depicts the SFP inside dimensions, the planned locations/placement of the primary and back-up channel sensors, and the proposed cable routing that extends the sensors toward the location of the electronics.

During the onsite audit, the licensee also provided drawings of the primary and back-up SFP level instrumentation. The NRC staff found the licensee’s response acceptable by reviewing Figure 1, “Surry Spent Fuel Pool Level Instrumentation Cable and Probe Layout,” and Figure 2, “Diagram of Mounting Bracket with Probe and Cable Connections.” The staff also walked down the SFP area and the primary and back-up cable route. The walk down started at the Cable Spreading Room (CSR) where the displays, control boxes and UPS are located. From the CSR, the staff visited the Auxiliary Building (AB) where the transmitter is mounted and then the SFP area which is the location for the SFPLI sensor probe and the exit point from the SFP area to the AB.

The NRC staff found that there is sufficient channel separation within the SFP area between the primary and back-up level instruments, sensor electronics, and routing cables to provide reasonable protection against 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 finds that, if implemented appropriately, the licensee's proposed arrangement for the SFPLI is 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 both the primary and backup systems will be installed as Seismic Category I to meet the NRC ISG JLD-ISG-2012-03 and NE112-02 guidance requirements.

In its August 8, 2013 letter [Reference 26], the licensee stated that the design criteria to be used to estimate the total loading on the mounting devices is an item to be supplied by the vendor per the Dominion procurement specification. The licensee also stated that the vendor had provided the following information:

> The flexible probe will have excursions that will result in some impacts to the liner. However, the flexible nature of the probe results in a self-relaxing response to static and hydrodynamic loading will dramatically limit the inertia and energy that the probe can impart to the liner.

By email dated July 11, 2013 [Reference 25], the NRC staff sent an RAI to the licensee. In RAI-3, the staff requested the licensee to address the methodology and design criteria that will be used to estimate the total loading on the mounting devices, inclusive of design basis maximum seismic loads and the hydrodynamic loads that could result from pool sloshing or other effects that could accompany such seismic forces. This RAI was carried over to the ISE the staff sent to the licensee by the letter dated November 1, 2013 [Reference 27] as RAI-2. In addition, the NRC staff requested, in RAI-3 of the ISE, the analyses used to verify the design criteria and methodology for seismic testing of the SFPI and the electronic units, including design-basis maximum seismic load and the hydrodynamic loads that could result from pool sloshing or other effects that could accompany such seismic forces. In RAI-4 of the ISE, the NRC staff requested, for each of the mounting attachment, a description of design inputs and the methodology that was used to qualify the structural integrity of the affected structures/equipment.

In its letters dated February 27, 2014 [Reference 29] and March 2, 2015 [Reference 31], the licensee stated that the mounting bracket design meets the Surry Power Station design and licensing basis requirements for Seismic Category I components, and includes consideration of static weight loads and hydrodynamic loads. The mounting bracket was qualified by analysis for the loading condition, including design-basis maximum seismic load and the hydrodynamic loads that could result from pool sloshing. The Surry-specific analysis of the mounting bracket was performed by Westinghouse and the methods, design criteria, and results of the analysis are documented in a Westinghouse calculation. The licensee also stated that Westinghouse document WNA-PT-00188-GEN, Rev. 1, "Spent Fuel Pool Instrumentation System (SFPIS) Standard Product Test Strategy," provides the overall test strategy for the spent fuel pool instrumentation system, and addresses the design criteria and methodology for seismic testing of the SFP instrumentation and the electronics units in Section 7. The test strategy includes seismic response spectra that envelope the design basis maximum seismic loads and includes applicable hydrodynamic loading that could result from conditions such as seismic-induced sloshing effects. In accordance with WNA-PT-00188-GEN, the seismic adequacy of the SFPIS equipment is demonstrated in accordance with the applicable guidance in Sections 7, 8, 9 and 10 of IEEE Standard 344-2004, "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," by testing (assemblies with active electronic components, sensor housing bracket, electronics panel mounting, coupler, and interconnecting cable) and analysis (sensor probe in pool and pool-side bracket). The licensee further stated that the level sensor consists of the braided stainless steel cable level probe, which is attached to the mounting bracket and extends into the pool. The attachment to the bottom of the mounting bracket and to the signal cable is made via a coaxial coupling. The mounting bracket is attached to the SFP structure at the concrete curb utilizing expansion-type concrete anchor bolts. The probe is not attached to the floor of the pool. A simplified drawing showing a representation of the attachment of the probe and the sensor cable to the mounting bracket (launch plate), and mounting bracket attachment to the SFP meet the requirement of the Surry design and licensing basis for Seismic Category I components including seismic loads, static weight loads and hydrodynamic loads. The licensee also stated that the level sensing probe is attached to the mounting bracket, which is anchored to the SFP structure at the concrete curb using concrete expansion anchors. The anchorage to the Seismic Category I SFP structure meets the design requirements. Each of the additional SFPIS components required to be mounted/anchored will be fixed to plant structures consistent with the Surry design and licensing basis for Seismic Category I components, and include consideration of design basis maximum seismic loads and static weight loads.

The NRC staff found the licensee responses acceptable and verified by reviewing licensee documentation and drawings describing the mounting bracket and anchor bolt dimensions, materials, and the seismic and hydrodynamic loads applicable to the mounting bracket configuration. As part of the onsite audit, the staff reviewed Figure 2, “Diagram of Mounting Bracket with Probe and Cable Connections” and Design Change SU-13-01042 Rev. 8, “Beyond Design Basis Spent Fuel Pool Level Instrumentation Installation,” in which it stated that verification that the sensor will not be thrown out of the pool during a seismic event is contained in Westinghouse letter LTR-SEE-II-13-47, Rev. 0 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”. In this letter, Westinghouse stated that if the bracket is constructed so that it can withstand certain minimum force (in lbf.), then the instrument will stay in pool. The staff reviewed calculation CN-PEUS-14-3 Rev. 1, “Seismic Analysis of the SFP Mounting Bracket for Surry Power Station, Millstone Power Station Unit 3, & North Anna Power Station” and noted that the calculated vertical sloshing pressure was calculated to be greater than the minimum required force. This pressure is bounded by the Westinghouse analysis. The staff also reviewed drawing NUS-2026 Rev. 4, “Detail No. R-I Standard Safety Related Conduit Support Surry Nuclear Power Station Unit 1&2”; and drawing 1301042-1-S-002 Rev. 1, “Installation Sketch Spent Fuel Pool Sensor Head Unit Mount Surry Power Station Unit 1”. The staff also walked down the SFP area and the primary and back-up cable route. The walk down started at the CSR where the displays, control boxes and UPS are located. From the CSR, the staff visited the AB where the electronic transmitter equipment is mounted and then the SFP area which is the location for the SFPLI sensor probe and the exit point from the SFP area to the AB. The NRC staff also reviewed Westinghouse’s SFPI system design specification, calculations and analyses, test plans, and test report and found the SFPI design and qualification process acceptable.

Based on the discussion above, the NRC staff finds that the licensee's proposed mounting design is 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 Design Features: Qualification

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 will be addressed in the engineering and design phase. These conditions will be considered for no fewer than seven days post-event or

until off-site resources can be deployed by the mitigating strategies resulting from Order EA-12-09. 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 Level 3 SFP water level,
- Temperatures of 212 degrees F and 100% relative humidity environment,
- Boiling water and/or steam environment,
- A concentrated borated water environment

In its letter dated August 8, 2013 [Reference 26], the licensee stated, in part, that:

> The probe that will be located in the spent fuel pool and the probe housing that will be located above the spent fuel pool will be certified for use in post-event conditions including temperatures in excess of 100° Centigrade, 100 percent condensing atmosphere, and exposure to postulated radiation levels with the fuel storage rack uncovered for an extended period of time. The remaining equipment will be installed in the mild environment of the Auxiliary Building or Service Building and qualified for use at temperatures up to 60° Centigrade, 100 percent condensing atmosphere, and 1x104 rads integrated dose. The inherent shielding of the structures along the line of sight between the fuel and the equipment will result in negligible doses to the equipment, even in the event that fuel is uncovered.

By letter dated November 1, 2013 [Reference 27], the NRC staff sent the ISE including RAIs to the licensee. In RAI-5, the staff requested the licensee to provide analysis of the maximum expected radiological conditions (dose rate and total integrated dose) to which the equipment (including transmitters, control boxes, and display panels) located will be exposed. In RAI-6, the staff requested the licensee to provide information indicating (a) temperature ratings and whether the temperature ratings for the system electronics (including transmitters, control boxes, and display panels) are continuous duty ratings; and, (b) the maximum expected ambient temperature in the rooms in which the system electronics will be located under BDB conditions in which there are no ac power available to run HVAC systems. In RAI-7, the staff requested the licensee to provide information indicating the maximum expected relative humidity in the rooms in which the system electronics will be located under BDB conditions, in which there are no AC power available to run HVAC systems, and whether the sensor electronics are capable of continuously performing its required functions under this expected humidity condition.

In its letter dated March 2, 2015 [Reference 31], the licensee stated that a radiation dose rate analysis was performed to support the radiological assessment requirements defined by NEI 12-02 for the SFP, Auxiliary Building areas, and Cable Spreading Rooms; the results are provided in Calculation RA-0047, "Radiological Evaluation following a Beyond Design Basis Surry Power Station (SPS) SFP Draindown for NEI 12-02." In the SFP area where the coupler and coaxial cable are located, the dose rate analysis resulted in a 7-day integrated dose of 2.9 x 10E6 Rads and a 40-year integrated dose of 880 Rads. In the Auxiliary Building where the SFPIS sensor transmitter is located, the dose rate analysis resulted in a 7-day integrated dose of 990 Rads and 40-year integrated dose of 880 Rads. In the Cable Spreading Rooms where the display cabinets are located, the dose rate analysis resulted in a 7-day integrated dose of 320 Rads and 40-year integrated dose of 270 Rads. These values were compared to the design criteria of 10E7 Rads for SFP area and 10E3 Rads for the Auxiliary Building area and formed the basis for demonstrating reliability of the permanently installed SFPIS. The licensee also stated that the SFP level instrumentation electronics utilize components containing Complementary Metal Oxide Semiconductor (CMOS) devices which have been found to be capable of withstanding ionizing dose radiation levels of up to 10E3 Rads. Comparing the calculated integrated dose for both the short-term post- BDB event and the long-term normal operating conditions to the industry accepted limit formed the basis to demonstrate reliability of the permanently installed sensor transmitter equipment located within the Auxiliary Building under post-BDB event radiological conditions.

The licensee also stated that the temperature rating for the electronic equipment located in the Auxiliary Building and the Cable Spreading Rooms (transmitter, control box, UPS display) is 120 °F based on a continuous duty rating and 140 °F under abnormal conditions. The basis for the temperature rating is provided Westinghouse design specification WNA-DS-02957-GEN, Rev. 2, Section 4.6. The temperature rating test results for abnormal conditions are provided in Westinghouse report EQ-QR-269, “Design Verification Testing Summary Report for the Spent Fuel Pool Instrumentation System” Section 4.5. The licensee also stated that the electronic transmitter equipment will be mounted within the Auxiliary Building one elevation below the SFP Operating Deck. The displays, control box and UPS are located in the Cable Spreading Rooms which are one elevation above the MCR. These areas of the Auxiliary Building are described in SU-EQUAL-00038-EZD, “Environmental Zone Description Surry Unit 1 and 2” and are not expected to exceed 105 degrees F (i.e., mild zone) during normal operations. The maximum temperature under postulated BDB conditions in which there is no ac power available to run HVAC systems is not expected to exceed 120 °F. The room temperatures were analyzed utilizing GOTHIC computation code for BDB conditions and the results are included in Addendum 00A to calculation SU-CALC-MEC-ME-0973, “Evaluation of Room Air Temperatures Following Extended Loss of AC Power (ELAP)”.

The licensee further stated that the electronic transmitter equipment will be mounted within the Auxiliary Building one elevation below the Spent Fuel Pool (SFP) Operating Deck. The displays, control boxes and UPS are located in the Cable Spreading Rooms one elevation above the MCR. The maximum humidity for Surry postulated BDB condition in which there is no ac power to run HVAC system is expected to be less than 95 percent relative humidity which was analyzed utilizing GOTHIC computational code and the results are included in Addendum 00A to Surry calculation SU-CALC-MEC-ME-0973, “Evaluation of Room Air Temperature Following Extended Loss of AC Power (ELAP)”. Equipment testing under normal and abnormal conditions with humidity levels up to 95 percent was performed by Westinghouse and the results documented in report EQ-QR-269, “Design Verification Testing Summary Report for the Spent Fuel Pool Instrumentation System” Section 4.5. The licensee also stated that the results from testing performed by Westinghouse compared to the maximum post BDB humidity level of 95 percent was found to be acceptable. This comparison formed the basis to demonstrate reliability of the permanently installed electronic equipment located within the Auxiliary Building and Cable Spreading Rooms under the BDB post event humidity conditions.

The NRC staff found the licensee's responses acceptable. As part of the onsite audit, the NRC staff reviewed Calculation RA-047, "Radiological Evaluation following a Beyond Design Basis Surry Power Station (SPS) SFP Drain-down for NEI 12-02." The staff found that the calculated integrated doses for both the normal condition and post-BDB event for the location where the SFPLI located are bounded by the acceptable limits. The staff also reviewed calculation SU-CALC-MEC-ME-0973, "Evaluation of Room Air Temperature Following Extended Loss of AC Power (ELAP)." The staff verified that the maximum temperature under postulated BDB conditions with no HVAC in the Auxiliary Building and Cable Spreading Rooms will not exceed 120 ºF for which the equipment is qualified for. The staff also verified that the maximum humidity under postulated BDB conditions with no HVAC in the Auxiliary Building and Cable Spreading Rooms will not exceed 95 percent humidity for which the equipment is qualified for. The staff noted that the SFPI, as designed, will envelope the environmental conditions of the installed SFPI locations.

The NRC staff also reviewed Westinghouse's SFPI system design specification, calculations and analyses, test plans, and test report and found the SFPI design and qualification process acceptable.

Depending on the installation configurations, Westinghouse provided two types of SFP cable connectors, a straight connector or a 90-degree connector. Both of them originally were qualified for a 15-month life. Westinghouse upgraded the aging qualification for the 90-degree connector, through testing, to 10 years for harsh environment. The test included radiation aging, thermal aging and steam tests. The straight connector can be installed at the SFP side only with additional installation requirements. During the onsite audit, the NRC staff inquired as to Surry's SFPI cable connector configuration. The licensee responded that at Surry, it uses 90-degree connectors at the pool side. These connectors are qualified to 10 years.

The NRC staff also inquired about an assessment of potential susceptibilities of Electromagnetic Interferences (EMI) 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 base configuration necessary to meet Criterion B (instrument will function before and after an Electro-Magnetic Compatibility (EMC) event was confirmed during EMC qualification testing performed by Westinghouse. NRC representatives audited the Westinghouse test documents. As a results Westinghouse specified materials, installation, and grounding requirements necessary to ensure the installed SFP level measurements system meets the tested EMI/RFI qualifications. These requirements and characteristics as detailed in Westinghouse letter LTR-EQ-14-32, Rev. 2 dated August 1, 2014. Additionally, placards will be installed in the Surry Auxiliary Building. The placards will read, "Be aware that use of hand-held radios within 3 ft. may cause interference with the SFP level channels. The reading returns to normal when radio usage is stopped." During the audit, as the results of the walkdown and discussions between the staff and the licensee, Surry provided the supplemental response to include the following statement:

The installation of the system in a configuration that is consistent with Westinghouse recommendations for equipment satisfies Performance Criterion B (see EQ-QR-269, Rev. 2). This includes the installation of a tracer wire between the probe launch plate and the sensor housing anywhere the coaxial cable is not routed in EMC (steel) conduit. For example, the SFPIS components were installed such that they were not mounted in close proximity to pumps, motors, or other EMI/RFI sources that could affect spent fuel pool level indication. The level transmitters are located in an area of the Auxiliary Building that is not near EMI/RFI-generating equipment that could have an adverse effect on the SFPLI system. The display cabinet hardware is mounted inside a qualified EMC enclosure in an area of the plant that prohibits the use of 2 way radios. And the system is grounded in a manner that is consistent with both the Westinghouse recommendations and well-established station grounding methods. Application of the steps described above provides assurance that the EMC testing performed by Westinghouse bounds the conditions in the plant. The systems have been installed and are providing accurate Spent Fuel Pool Level indication. The Site Acceptance test and initial loop calibrations were completed satisfactorily on 1/14/2015. The NRC staff found the responses acceptable. The licensee has taken steps to assure that the EMC testing by Westinghouse bounds the conditions of the plant. The licensee also completed the site acceptance test and verified that the systems have been installed properly and provided the SFP level indication with accuracy within the vendor-specified tolerances.

Based on the discussion above, the NRC staff finds the licensee's proposed instrument qualification process 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, in part, that the primary instrument channel will be redundant to and independent of the back-up instrument channel. Both the primary and back-up instrument channels will be of the same technology, manufacturer, and model. Independence will be achieved through physical separation of the final installed instruments. The two permanently installed instrument sensors will be separated by a distance comparable to the shortest length of a side of the pool, to the extent practical, based on the existing SFP geometry and construction. The cables associated with each channel will follow separate and independent routes from the instruments to each electronics' enclosure and from the enclosures to the displays. The normal ac or dc power source for each channel will be provided from independent and separate sources.

In its letter dated August 8, 2013 [Reference 26], the licensee stated, in part, that the Surry probes will be located on opposite ends of the longest side of the spent fuel pool. The signal conditioning enclosures will be located in the Auxiliary Building, and the read-out/display units (electronics enclosures) will be located in the Cable Spreading Room which is within the Seismic Class I portion of the Service Building. Dominion's standard separation criteria for safety related instrument cable will be applied. Each level channel is powered from its own dedicated 24-volt dc sealed batteries with a charging source connected to ac power from different sources. Therefore, the loss of one power source will not result in the loss of both channels. In addition to the normal dc power supply to each channel, a back-up power source will also be available to each channel in the form of a portable back-up battery and connections to alternate power sources independent of the normal ac or dc power sources.

By letter dated November 1, 2013 [Reference 27], the NRC staff issued an ISE, which included RAI-13. In this RAI, the staff requested the licensee to provide a description of the electrical ac power sources and capabilities for the primary and backup channels. The staff also requested the licensee to provide the final configuration of the power supply source for each channel so that the staff may conclude that the two channels are independent from a power supply assignment perspective.

In its letter dated March 2, 2015 [Reference 31], the licensee stated that each instrumentation channel is normally powered by 120 Vac distribution panels to support continuous monitoring of the SFP level. The 120 Vac distribution panels for the primary and backup channels are powered by different 480 Vac buses. Therefore, the loss of any one 480 Vac bus will not result in the failure of both instrument channels. On loss of normal 120 Vac power, each channel is equipped with a separate uninterruptible power supply (UPS) that will automatically transfer to a dedicated back-up battery. If normal power is restored, then the channel will automatically transfer back to the normal 120 Vac power source. The backup batteries are maintained in a charged state by associated UPS. The staff found the licensee's response acceptable. As part of its onsite audit, the NRC staff verified that the power supply source for each channel is independent by reviewing Design Change SU-13-01042,"Beyond Design Basis Spent Fuel Pool Level Instrument Installation," Rev. 8 (Page 15 of 123); Drawing Nos. 1301042-11548-LP-2514-A Rev. 0, "Lighting Panelboard Schedule 02-EP-LP-2S14 Surry Power Station – Unit 2"; 11548-FE-13A Rev. 17, "Wiring Diagram Lighting Distribution Surry Power Station – Unit 2"; 11548-FE-1C Rev. 14, "4160V One Line Diagram Surry Power Station – Unit 2"; 1301042-11448-LP-1S14-B Rev. 1, "Lighting Panelboard Schedule 01-EP-LP-1S14 Surry Power Station – Unit 1"; 11448-FE-13A Rev. 28, "Wiring Diagram Lighting Distribution Surry Power Station – Unit 1"; and 11448-FE-1C Rev. 24, "One Line Diagram 4160V Transfer Bus F Surry Power Station – Unit 1". The NRC staff also walked down the SFP area and the route for the primary and back-up cables. The walk-down started at the CSRs where licensee indicated the locations for the SFPI display cabinets, the electrical power sources, and the connections for the displays. The NRC staff walked the complete cable routing from the SFP to the CSRs for the primary and back-up SFPI.

Based on the discussion above, the NRC staff finds that the licensee's proposed design, with respect to instrument channel independence, is 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 the normal power supply for each channel will be provided by different power sources such that loss of one power source will not result in the loss of both channels. In addition to the normal plant ac and/or dc power supply to each channel, a back-up power source will also be provided to each channel in the form of a back-up battery independent of the normal ac or dc power sources.

In its letter dated August 8, 2013 [Reference 26], the licensee stated, in part, that the power source for each level channel is based on 24-volt dc sealed batteries and a charging source connected to ac power from different sources. Therefore, the loss of one power source will not result in the loss of both channels. In addition to the normal dc power supply to each channel, a back-up power source will also be available to each channel in the form of a portable back-up battery and connections to alternate power sources which are independent of the normal ac or dc power sources. Identification of the specific ac power sources will be available upon completion of the final design, scheduled for December 2013 and will be forwarded to the NRC during the subsequent scheduled status update. The seismically qualified batteries are designed to supply power for the entire level monitoring channel for at least seven days after a station black out (SBO). The electronics enclosures and associated electronics are qualified for continuous operation in an operating environment of 0-50 degrees Centigrade and 95 percent humidity, non-condensing atmosphere without the need for cooling fans. Since the system is designed to support continuous operation over a seven-day or longer SBO period, there is sufficient time to either restore or provide a backup source of ac power to recharge the 24-volt batteries. Deployment of an ac power source to recharge the level monitoring channel batteries will be included in the FLEX implementing procedures. As such, each channel will be available to run reliably and continuously following the onset of a BDB event for the minimum duration needed.

By letter dated November 1, 2013 [Reference 27], the NRC staff issued an ISE, which included RAI-14. In RAI-14, the staff requested the licensee to provide the results of the calculation depicting the battery backup duty cycle requirements demonstrating that its capacity is sufficient to maintain the level indication function until offsite resource availability is reasonably assured.

In a letter dated February 27, 2014 [Reference 29], the licensee stated that Westinghouse document WNA-CN-00300-GEN, "Spent Fuel Pool Instrumentation System Power Consumption Calculation," Rev. 0, documents the SFPIS power consumption analysis. Table 5-7 (Level Wired Cabinet, 3-Day Battery Charge Power Consumption) reflects the configuration to be used at Surry. The calculation concludes that, with an initial full charge, the battery will maintain the level indication function without ac power for 101.21 hours (4.22 days). With an externally power remote display (in the MCR) connected to the SFPIS (that consumes no more than 0.064 Amps), the battery can maintain the level indication function for 3 days. The results of the calculation show the battery will provide adequate time for off-site resources to be deployed by the mitigating strategies resulting from Order EA-049. The NRC staff found the licensee's response acceptable. 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 finds that the licensee's proposed power supply design is 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 the instrument channels will maintain their design accuracy following a power interruption or change in power source without requiring recalibration. Since the instrumentation is generally commercial off the shelf supplied components, the vendor published instrument accuracies will be verified as acceptable and will be used as a basis for final configuration and calibration I procedures. Accuracy requirements will consider SFP conditions, e.g., saturated water, steam environment, and 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. Specific details regarding accuracy will be obtained from the supplier during the detailed design phase.

In its letter dated November 1, 2013 [Reference 27], the NRC staff issued an ISE, which included RAI-15. In RAI-15, the staff requested the licensee to provide a) description of the methodology that will be used for determining the maximum allowed deviation from the instrument channel design accuracy that will be employed under normal operating conditions as an acceptance criterion for a calibration procedure to flag to operators and to technicians that the channel requires adjustment to within the normal condition design accuracy and b) analysis verifying that the proposed instrument performance is consistent with these estimated accuracy normal and BDB values. The staff also requested the licensee to demonstrate that the channels will retain these accuracy performance values following a loss of power and subsequent restoration of power.

In a letter dated February 27, 2014 [Reference 29], the licensee stated that Westinghouse document WNA-DS-02957-GEN, "Spent Fuel Pool Instrumentation System Design Specification," Rev. 2, specifies the required display accuracy of the level indication as within ± 3 inches of the entire range, which is from normal water level to the top of the fuel racks for all environmental conditions. Westinghouse document WNA-CN-00301-GEN, "Spent Fuel Pool Instrumentation System Channel Accuracy Analysis," Rev. 0, provides the SFPIS channel accuracy analysis. Westinghouse document WNA-TP-04709-GEN, "Calibration Procedure," Rev. 3, provides the instructions for calibration for the SFPIS. Westinghouse document WNA-CN-00301-GEN, Rev. 0, "Spent Fuel Pool Instrumentation System Channel Accuracy Analysis," provides the SFPIS channel accuracy analysis verifying that the instrument performance is consistent with the accuracy requirements during normal and abnormal conditions. Westinghouse document WNA-TP-04709-GEN, Rev. 3, "Calibration Procedure," provides the instruction for routine calibration of the SFPIS to ensure that instrument performance is consistent with accuracy requirements during operation. The results of qualification testing are documented in Westinghouse Design Verification Testing Summary Report EQ-QR-269. These results demonstrate that the channel retained the design accuracy at the completion of each test including loss of power and subsequent restoration of power. During the onsite audit, the NRC staff reviewed the results of site acceptance test report LTR-SFPIS-14-120, Rev. 0; and Data Sheet 0-ICP-FC-L-105-2, "Indicator and PCS Point Data Sheet" dated January 14, 2015 and found the test results met the vendor designed accuracy values and therefore, the staff found the response acceptable.

The NRC staff also reviewed the Westinghouse's SFPI system design specifications, calculations and analyses, test plans, and test reports and found the SFPI design with respect to the system accuracy reasonable.

Based on the discussion above, the NRC staff finds that the licensee's proposed instrument accuracy is 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

> Instrument channel design will provide for routine testing and calibration consistent with Order EA-12-051and the guidance in NEI12-02. The installed sensors will be designed to allow testing and/or calibration via in-situ methods while mounted in the pool. Removal of the sensor from the pool will not be required for calibration or testing.

In its letter dated August 8, 2013 [Reference 28], the licensee stated, in part, that

a) Calibration of the SFP level system will be performed in-situ. Channel check and calibration tolerances will be developed as part of the detailed design. The final calibration methodology will be available upon completion of the final design, scheduled for December 2013, and will be forwarded to the NRC during the subsequent scheduled status update.

b) The two independent channels of the SFP level instrumentation system will be cross-checked against each other. Since the two wide-range level channels are independent, a channel check tolerance based on the design accuracy of each channel will be applied for cross-comparison between the two channels.

c) The wide-range instruments may also be cross-checked against the existing ultrasonic narrow-range pool level measurement channels. If deemed necessary, tolerances for this cross-check will be developed as part of the final design.

d) Specific details of the functional and calibration test program, including frequencies, will be developed in accordance with the vendor's recommendations as part of the final instrument design.

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 finds the licensee's proposed design, with respect to routine in-situ instrument channel functional and calibration tests, to be consistent with NEI 12-02, as endorsed by JLD-ISG-2012-03.

Based on the discussion above, the NRC staff finds that the licensee's proposed SFP instrumentation design allows for testing consistent with NEI 12-02 guidance, as endorsed, by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2.9 Design Features: Display

In its OIP, the licensee stated that the conceptual design located the electronics enclosure and primary display in the Cable Spreading Room and that specific details regarding the display and display location(s) would be finalized during the detailed design phase. In its letter dated August 8, 2013 [Reference 26], the licensee stated, in part, that the current design places the instrument channel read-out/display units (electronics enclosure) for both channels in the Cable Spreading Room which is within the Seismic Category I portion of the Service Building. This area will be accessible from the MCR from primary and alternate routes. The final design will verify that the habitability of the access routes and locations in the Service Building where the instrument channel read-out/display units are planned will be located outside of any very high radiation areas or locked high radiation area during normal operation or various drain-down conditions. Communications with the MCR and/or Technical Support Centers will be maintained via two-way radio. Staffing and communications capabilities for both units will be verified by the FLEX Strategy validation commitments made in response to Order EA-12-049.

By letter dated November 1, 2013 [Reference 27], the NRC staff issued an ISE and RAI. In RAI-16, the staff requested the licensee to describe the evaluation used to validate that the displays located outside the main control room can be accessed without unreasonable delay following a BDB event. The staff also requested the licensee to a) include the time available for personnel to access the display as credited in the evaluation, as well as the actual time (e.g., based on walk-throughs) that it will take for personnel to access the display, b) include a description of the radiological and environmental conditions on the paths personnel might take, c) describe whether the display location remains habitable for radiological, heat and humidity, and other environmental conditions following a BDB event, and d) describe whether personnel are continuously stationed at the display or monitor the display periodically.

In its letter dated March 2, 2015 [Reference 31], the licensee stated that the primary display location will be located in the Unit 1 Cable Spreading room directly above the Main Control Room near the Appendix “R” remote monitoring panels. This location was selected due to its proximity to a current Appendix R access path inside a seismic structure and having prompt access to the Main Control Room that allows rapid access for the emergency response staff to and from the display. Due to the physical distance from the SFP and shielding from structures, exposure to personnel monitoring SFP levels would remain less than emergency exposure limits allowance for emergency responders to perform this action, per the Surry Emergency Plan. Heat and humidity from SFP boil-down conditions have been evaluated for this location in Calculation ME-0973, Rev. 0, Addendum 00A. The secondary display location is in the Unit 2 Cable Spreading Room. The secondary monitoring location allows rapid access to and egress from the main control room via pathways that are enclosed within seismically qualified structures. This location has similar characteristics physically to the Unit 1 Cable Spreading room and would not be significantly different with regard to exposure during accident scenarios or habitability from the primary location. Spent fuel pool level display monitoring will be primarily the responsibility of the Service Building Inside Operator, who will normally perform periodic monitoring at the location where the primary display will be mounted, once dispatched from the Control Room. Travel time from the Control Room to the primary display is approximately 1 minute based on the licensee’s walkdowns. Travel time from the Control Room to the secondary display location is approximately 1 minute based on the walkdowns. The staff found the licensee’s response acceptable and verified during a walk down. The staff found that the display location will be promptly accessible and will remains habitable.

An additional remote display powered from 1-FC-CAB-105-1 is located in the MCR.

Based on the discussion above, the NRC staff finds that the licensee's proposed location and design of the SFP instrumentation displays is 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 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.

Based on the discussion above, the NRC staff finds 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, if implemented correctly, should 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 SFP instrumentation. In its letter dated August 8, 2013 [Reference 26], the licensee stated, in part, that procedures for inspection, maintenance, repair, operation, abnormal response, and administrative controls associated with the SFP level instrumentation will be developed in accordance with vendor recommendations using existing station administrative and technical procedures that govern procedure development. These procedures ensure standardization of format and terminology, ease of use, and a consistent level of quality. A detailed list of procedures to be developed and the technical objectives of the procedures will be available following completion of the final design, scheduled for December 2013, and will be forwarded to the NRC during the subsequent scheduled status update.

By letter dated November 1, 2013 [Reference 27], the NRC staff issued an ISE and requested the licensee provided additional information. In RAI-17 the staff requested the licensee to provide a list of the procedures addressing operation (both normal and abnormal response), calibration, test, maintenance, and inspection procedures that will be developed for use of the spent SFP instrumentation. The staff also requested the licensee to include a brief description of the specific technical objectives to be achieved within each procedure.

In its letter dated July 20, 2015 [Reference 33], the licensee stated that appropriate quality assurance measures that are consistent with Appendix A-1 of NEI 12-02 have been established for the SFP level instrumentation as required by Order EA-12-051. Procedures for system inspection, calibration and test, maintenance, repair, operation, and normal and abnormal responses have been provided by Westinghouse. Corresponding site-specific procedures have either been developed based on these vendor documents or a Recurring Task Evaluation (RTE) has been established to evaluate, prepare, and implement the stated PM procedures at the recommended frequencies. A list of procedures and RTEs supporting the Surry SFP Level Instrumentation is provided below. Technical objectives for the various types of procedures are also included.

1) System Inspection -- To verify the system components are in place, complete, and in the correct configuration.

- LOG-SBIS-001R: Procedure to conduct plant walkdowns and record SFPLI System status, conditions, and level readings.

2) Calibration and Test -- To verify that the system is within specified accuracy, is functioning as designed, and is properly indicating SFP level.

- 0-ICP-FC-L-105-1, "Spent Fuel Pool Level (1-FC-L-105-1) Calibration."
- 0-ICP-FC-L-105-2, "Spent Fuel Pool Level (1-FC-L-105-2) Calibration."

3) Maintenance -- To establish and define scheduled and preventative maintenance (PM) requirements and activities necessary to minimize the possibility of interruption.

- RTE # P-SURR-340705: PM for 24 Volt Battery Replacement at 3-Years [e.g., Battery Replacement Before End of Life].
- RTE # P-SURR-340706: PM to Perform 18-Month Loop Calibration of the BDB SFP Wide Range Level Indication System.
- RTE # P.-SURR-340707: PM to Replace Cable and Connectors at 10-Years.
- RTE # P-SURR-340708: PM to Replace Transmitter Electronics Module.
- RTE # P-SURR-340709: PM to Replace Electronics Enclosure Components at 10-years.

4) Repair -- To specify troubleshooting steps and component repair and replacement activities in the event of a system malfunction.

- Work Management Process: A Condition Report (CR) is written when a deviating condition is found. The CR is evaluated by the Station Condition Report Review Team (CRT) and a Corrective Action (CA) is assigned to the responsible organization. Work orders are developed to address/repair the deviating condition. The system Technical Manual and repair procedures supplied by Westinghouse are available as input into the work orders.

5) Operation -- To provide sufficient instructions for operation and use of the system by plant staff personnel.

- Knowledge Based Training is conducted during initial Operator Qualification and has been integrated into the Continuing Operator Training Program. Initial training has been completed for current operations personnel.

6) FLEX Support Guideline (FSG) -- To define the actions to be taken upon observation of system level indications, including actions to be taken at the levels defined in NEI 12-02.

- Emergency Contingency Action, ECA-0.0, "Loss of All A/C Power": This procedure directs the operator to procedure 0-AP-22.02, "Malfunction of Spent Fuel Pool System", which provides guidance for checking and monitoring fuel pool level. When level is low, the procedure directs the user to FSG-11, "Alternate SFP Makeup and Cooling."

- FSG-5, "Initial Assessment & Equipment Staging": When the High Capacity Pumps are staged, the procedure directs the user to FSG-11 to monitor and to add water to SFP as required.

- FSG-11, "Alternate SFP Makeup and Cooling": Provides instruction for monitoring and adding water to SFP. FSG-11 also provides instruction for the use of alternate power to the primary and backup instrument channels.

Based on the discussion above, the NRC staff finds that the licensee's proposed procedure development, if implemented correctly, should 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 back-up 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 November 1, 2013 [Reference 27], the NRC staff issued an ISE, which also included RAIs. In RAI-18, the staff requested the licensee: a) describe the maintenance and testing program the licensee will establish and implement to ensure that regular testing and calibration is performed and verified by inspection and audit to demonstrate conformance with design and system readiness requirements, b) describe compensatory actions when both channels are out-of-order and the implementation procedures, and c) provide additional information describing expedited and compensatory actions in the maintenance procedure to address when one of the instrument channels cannot be restored to functional status within 90 days.

In its letter dated March 2, 2015 [Reference 31], the licensee stated that channel check is not a specified requirement in NEI 12-02. Channel check is specified in IEEE 338-1987 for safety systems. The SFPLI channels are not safety-related and are not subject to testing requirements of safety-related instrumentation. If the plant staff determined a need to confirm the two channels are performing as expected, the two channels may be read in the Units 1 and 2 Cable Spreading Rooms. While the SFP is operating within design-basis and at normal level, the indicators may be compared to fixed marks within the SFP by visual observation to confirm indicated level. The periodic calibration verification will be performed. The periodic calibration verification will be performed considering normal testing scheduling allowance (e.g., 25 percent). Periodic calibration verification procedures will be in place based on information provided by Westinghouse in WNA-TP-04709-GEN, “Spent Fuel Pool Instrumentation System Calibration Procedure.” Preventive maintenance procedures for the backup batteries will be in place based on recommendation from Westinghouse. Provisions associated with out of service (OOS) or non-functional equipment including allowed outage time (AOT) and compensatory actions will be considered within the guidance provided in Section 4.3 of NEI 12-02. If one OOS channel cannot be restored to service within 90 days, appropriate compensatory actions, including the use of alternate suitable equipment, will be taken. If both channels become OOS, actions would be initiated within 24 hours to restore one of the channels to operable status and to implement appropriate compensatory actions, including the use of alternate suitable equipment and/or supplemental personnel, within 72 hours. Additionally, if both channels are OOS, a condition report will be initiated and addressed through the Dominion's Corrective Action Program. Surry will maintain sufficient spare parts for the SFPIS, taking into account the lead time and availability of spare parts, in order to expedite maintenance activities, when necessary, to provide assurance that a channel can be restored to service within 90 days.

During the onsite audit, the NRC staff expressed a concern about channel check not to be performed. As the result of the discussions between the staff and the licensee, Surry provided a supplemental response to include the following statement:

> "Operators will record the SFP level from both channels of the SFP level indicator as part of operation walkdowns. Each reading will have nominal operating range [e.g., +/- value] for the SFP level. The reading from the SFPLI will be compared to each other. There will be an established acceptable delta between both values obtained from the SFPLI indicators. If either reading is outside the nominal operating range or the difference in the readings exceeds the established acceptable delta, a condition report (CR) will be submitted and corrective actions will be assigned to resolve the discrepancy. The staff found the responses acceptable. The licensee will perform periodic calibration verification and will consider provision for OOS or non-functional equipment including AOT and compensatory actions. The licensee will record the SFP level from both channels of the SFP level indicator as part of operation walkdowns."

Based on the discussion above, the NRC staff finds that the licensee's proposed testing and calibration plan, if implemented correctly, should 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 July 20, 2015 [Reference 33], the licensee stated that it has completed the requirements of Order EA-12-051 and Surry, Unit Nos. 1 and 2 are in full compliance with the order 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's plans conform to the guidelines of NEI 12-02, as endorsed, by JLD-ISG-2012-03. In addition, the NRC staff concludes that if the SFPLI is installed at Surry 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 April 2015 [Reference 17]. The licensee reached its final compliance date in January 2016 [Reference 44], 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.

6.0 REFERENCES

1. SECY-11-0093, "Recommendations for Enhancing Reactor Safety in the 21st Century, the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident," July 12, 2011 (ADAMS Accession No. ML11186A950)

2. 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," February 17, 2012 (ADAMS Accession No. ML12039A103)

3. SRM-SECY-12-0025, "Staff Requirements – 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," March 9, 2012 (ADAMS Accession No. ML120690347)

4. Order EA-12-049, "Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events," March 12, 2012 (ADAMS Accession No. ML12054A736)

5. Order EA-12-051, "Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation," March 12, 2012 (ADAMS Accession No. ML12054A679)

6. Nuclear Energy Institute document NEI 12-06, "Diverse and Flexible Coping Strategies (FLEX) Implementation Guide," Revision 0, August 21, 2012 (ADAMS Accession No. ML12242A378)

7. JLD-ISG-2012-01, "Compliance with Order EA-12-049, Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events," August 29, 2012 (ADAMS Accession No. ML12229A174)

8. Nuclear Energy Institute 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, August 24, 2012 (ADAMS Accession No. ML12240A307)

9. JLD-ISG-2012-03, "Compliance with Order EA-12-051, Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation," August 29, 2012 (ADAMS Accession No. ML12221A339)

10. Letter, Virginia Electric and Power Company, to NRC, "Surry, Units 1 and 2 - Overall Integrated Plan in Response to March 12, 2012, Commission Order to Modify Licenses With Regard To Requirements for Mitigation Strategies for Beyond Design Basis External Events, EA-12-049," February 28, 2013 (ADAMS Accession No. ML13063A181)

11. Letter, Virginia Electric and Power Company to NRC, "Surry, Units 1 and 2 - Six-Month Status Report in Response to March 12, 2012, Commission Order to Modify Licenses With Regard To Requirements for Mitigation Strategies for Beyond Design Basis External Events (Order Number EA-12-049)," August 23, 2013 (ADAMS Accession No. ML13242A013)

12. Letter, Virginia Electric and Power Company to NRC, “Surry Power Station Units 1 and 2 - Six-Month Status Report in Response to March 12, 2012, Commission Order to Modify Licenses With Regard To Requirements for Mitigation Strategies for Beyond Design Basis External Events (Order Number EA-12-049),” February 27, 2014 (ADAMS Accession No. ML14069A015)

13. Letter, Virginia Electric and Power Company to NRC, “Surry, Units 1 and 2 - Six-Month Status Report in Response to March 12, 2012, Commission Order to Modify Licenses With Regard To Requirements for Mitigation Strategies for Beyond Design Basis External Events (Order Number EA-12-049),” August 28, 2014 (ADAMS Accession No. ML14251A035)

14. Letter, Virginia Electric and Power Company to NRC, “Surry Power Station Units 1 and 2 - Six-Month Status Report in Response to March 12, 2012, Commission Order to Modify Licenses With Regard To Requirements for Mitigation Strategies for Beyond Design Basis External Events (Order Number EA-12-049),” March 2, 2015 (ADAMS Accession No. ML15069A234)

15. Letter from Jack R. Davis (NRC) to All Operating Reactor Licensees and Holders of Construction Permits, "Nuclear Regulatory Commission Audits of Licensee Responses to Mitigation Strategies Order EA-12-049," August 28, 2013 (ADAMS Accession No. ML13234A503)

16. Letter from Jeremy S. Bowen (NRC) to David Heacock, (Dominion), “Interim Staff Evaluation Relating to Overall Integrated Plan in Response to Order EA-12-049 (Mitigation Strategies),” February 19, 2014 (ADAMS Accession No. ML14002A145)

17. Letter from Tony Brown (NRC) to David Heacock, (Dominion), “Report for the Onsite Audit Regarding Implementation of Mitigating Strategies and Reliable Spent Fuel Pool Instrumentation Related to Orders EA-12-049 and EA-12-051,” April 14, 2015 (ADAMS Accession No. ML15096A391)

18. Letter, Dominion to NRC, “Surry Power Station Unit 1 - Compliance Letter in Response to the March 12, 2012 Commission Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design Basis-External Events (Order Number EA-12-049),” July 22, 2015 (ADAMS Accession No. ML15209A503)

19. U.S. Nuclear Regulatory Commission, "Request for Information Pursuant to Title 10 of the Code of Federal Regulations 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3, of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident," March 12, 2012, (ADAMS Accession No. ML12053A340)

20. SRM-COMSECY-14-0037, “Staff Requirements – COMSECY-14-0037 – Integration of Mitigating Strategies For Beyond-Design-Basis External Events and the Reevaluation of Flooding Hazards," March 30, 2015, (ADAMS Accession No. ML15089A236)

21. Letter, Virginia Electric and Power Company (Dominion), “Surry Power Station Units 1 and 2 - Flood Hazard Reevaluation Report in Response to March 12, 2012, Information

Request Regarding Flooding Aspects of Recommendation 2.1," March 12, 2015 (ADAMS Accession No. ML15078A291)

22. Letter, Virginia Electric and Power Company (Dominion) to NRC, "Surry, Units 1 & 2 Response to March 12, 2012 Information Request Seismic Hazard and Screening Report (CEUS Sites) for Recommendation 2.1," March 31, 2014 (ADAMS Accession No. ML14092A414)

23. Letter from Jack R. Davis (NRC) to Joseph E. Pollock (NEI), "Staff Assessment of National SAFER Response Centers Established In Response to Order EA-12-049," September 26, 2014 (ADAMS Accession No. ML14265A107)

24. Surry, Units 1 and 2, Overall Integrated Plan in Response to March 12, 2012 Commission Order Modifying Licenses with Regard to Requirements for Reliable Spent Fuel Pool Instrumentation (Order EA-12-051),dated February 28, 2013 (ADAMS Accession No. ML13063A013)

25. Email from Karen Cotton (NRC) to David Heacock, "RAI – Reliable Spent Fuel Pool (SFP) Instrumentation (Order EA-12-051) for Surry Power Station, Units 1 and 2," dated July 11, 2013 (ADAMS Accession No. ML13280A058)

26. Surry, Units 1 & 2, March 12, 2012 Commission Order Modifying License with Regard to Requirements for Reliable Spent Fuel Pool Instrumentation (Order No. EA-12-051) Request for Additional Information (RAI) Response, dated August 8, 2013 (ADAMS Accession No. ML13225A007)

27. Surry Power Station, Units 1 and 2, Interim Staff Evaluation and Request for Additional Information Regarding the Overall Integrated Plan For Implementation of Order EA-12-051, Reliable Spent Fuel Pool Instrumentation (TAC Nos. MF1004, MF1005), dated November 1, 2013 (ADAMS Accession No. ML13298A625)

28. Virginia Electric & Power Company, "Surry Power Station, Units 1 and 2 - Six-Month Status Report in Response to March 12, 2012 Commission Order Modifying Licenses with Regard to Reliable Spent Fuel Pool," dated August 23, 2013 (ADAMS Accession No. ML13242A016)

29. Virginia Electric & Power Company, "Surry Power Station, Units 1 and 2 - Second Six-Month Status Report in Response to March 12, 2012 Commission Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation (Order EA-12-051)," February 27, 2014 (ADAMS Accession No. ML14069A010)

30. Virginia Electric & Power Company, "Surry, Units 1 and 2 - Six-Month Status Report in Response to March 12, 2012 Commission Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation (Order EA-12-051)," August 26, 2014 (ADAMS Accession No. ML14245A402)

31. Virginia Electric & Power Company, "Surry, Units 1 and 2 - Six-Month Status Report in Response to March 12, 2012 Commission Order Modifying Licenses with Regard to

Reliable Spent Fuel Pool Instrumentation (Order EA-12-051)," March 2, 2015 ADAMS (ADAMS Accession No. ML15069A229)

32. Virginia Electric & Power Company (Dominion), "Surry Power Station, Units 1 and 2 – Supplement Information Regarding Compliance with EA-12-051 Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation," dated July 27, 2016 (ADAMS Accesion No. ML16214A262)

33. Virginia Electric & Power Company (Dominion), "Surry Power Station, Units 1 and 2 – Confirmation of Compliance with EA-12-051 Order Modifying Licenses with Regard to Reliable Spent Fuel Pool Instrumentation," dated July 20, 2015 (ADAMS Accession No. ML15205A342)

34. Letter from Jason Paige (NRC) to Joseph Shea, "Watts Bar Plant Units 1 and 2 – Report for the Westinghouse Audit in Support of Reliable Spent Fuel Pool Instrumentation Related to Order EA-12-051 (TAC Nos. MF0951 and MF1178)," August 18, 2014 (ADAMS Accession No. ML14211A346)

35. NRC Office of Nuclear Reactor Regulation Office Instruction LIC-111, Regulatory Audits, dated December 16, 2008 (ADAMS Accession No. ML082900195)

36. Letter from William Dean (NRC) to Power Reactor Licensees, "Coordination of Requests for Information Regarding Flooding Hazard Reevaluations and Mitigating Strategies for Beyond-Design Bases External Events," September 1, 2015 (ADAMS Accession No. ML15174A257)

37. NEI Position Paper: "Shutdown/Refueling Modes", dated September 18, 2013 (ADAMS Accession No. ML13273A514)

38. Letter from Jack R. Davis (NRC) to Joseph E. Pollock (NEI), regarding NRC endorsement of NEI Position Paper: "Shutdown/Refueling Modes", September 30, 2013 (ADAMS Accession No. ML13267A382)

39. Letter from Nicholas Pappas (NEI) to Jack R. Davis (NRC), "FLEX Equipment Maintenance and Testing," October 3, 2013 (ADAMS Accession No. ML13276A573)

40. Letter from Jack R. Davis (NRC) to Joseph E. Pollock (NEI), "NRC endorsement of the use of the EPRI FLEX equipment maintenance report," October 7, 2013 (ADAMS Accession No. ML13276A224)

41. EPRI Draft Report, 3002000704, "Seismic Evaluation Guidance: Augmented Approach for the Resolution of Near-Term Task Force Recommendation 2.1: Seismic" (ADAMS Accession No. ML13102A142)

42. Letter, Virginia Electric and Power Company to NRC, "Surry Power Station, Units 1 & 2, Supplement to Overall Integrated Plan in Response to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events (Order Number EA-12-049)", April 30, 2013 (ADAMS Accession No. ML13126A208)

43. Letter, Virginia Electric and Power Company to NRC, “Surry Power Station, Units 1 & 2, Fifth Six-Month Status Report in Response to March 12, 2012, Commission Order to Modify Licenses With Regard To Requirements for Mitigation Strategies for Beyond Design Basis External Events (Order Number EA-12-049),” August 24, 2015 (ADAMS Accession No. ML15244B202)

44. Letter, Dominion to NRC, “Surry, Units 1 and 2 - Compliance Letter and Final Integrated Plan in Response to the March 12, 2012 Commission Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond Design Basis External Events (Order Number EA-12-049),” January 25, 2016 (ADAMS Accession No. ML16033A353)

45. Letter from Victor Hall (NRC) to David Heacock, Dominion, “Surry Power Station, Unit Nos. 1 and 2 – Interim Staff Response to Reevaluated Flood Hazards Submitted in Response to 10 CFR 50.54(f) Information Request – Flood-Causing Mechanism Reevaluation,” February 29, 2016 (ADAMS Accession No. ML16041A341)

46. Letter from Nicholas Pappas (NEI) to Jack R. Davis (NRC), “Alternative Approach to NEI 12-06 Guidance for Hoses and Cables,” May 1, 2015 (ADAMS Accession No. ML15126A135)

47. Letter from Jack R. Davis (NRC) to Joseph E. Pollock (NEI), regarding response to NEI’s request for “Alternative Approach to NEI 12-06 Guidance for Hoses and Cables,” May 18, 2015 (ADAMS Accession No. ML15125A442)

48. COMSECY-14-0037, “Integration of Mitigating Strategies for Beyond-Design-Basis External Events and the Reevaluation of Flooding Hazards,” dated November 21, 2014 (ADAMS Accession No. ML14309A256)

49. Letter from NRC to The Operating Power Reactor Licensees on the Enclosed List, Regarding Screening and Prioritization Results Regarding Seismic Hazard Reevaluations for Recommendation 2.1 of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident, dated October 3, 2014 (ADAMS Accession No. ML14258A043)

50. Letter from NRC to The Power Reactor Licensees on the Enclosed List, Regarding Final Determination of Licensee Seismic Probabilistic Risk Assessments Under the Request for Information Pursuant to Title 10 of the *Code of Federal Regulations 50.54(f)* Regarding Recommendation 2.1 “Seismic” of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident, dated October 27, 2015 (ADAMS Accession No. ML15194A015)

51. U.S. Nuclear Regulatory Commission, "Mitigation of Beyond-Design-Basis Events," Federal Register, Vol. 80, No. 219, November 13, 2015, pp. 70610-70647.

52. Nuclear Energy Institute document NEI 12-06, “Diverse and Flexible Coping Strategies (FLEX) Implementation Guide,” Revision 2, December 31, 2015 (ADAMS Accession No. ML16005A625)

53. JLD-ISG-2012-01, "Compliance with Order EA-12-049, Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events," Revision 1, January 22, 2012 (ADAMS Accession No. ML15357A163)

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Date: August 4. 2016

By letter dated February 28, 2013 (ADAMS Accession No. ML13063A013), Dominion submitted its OIP for Surry, Unit Nos. 1 and 2, in response to Order EA-12-051. At six-month intervals following the submittal of its 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 SE. By letters dated November 1, 2013 (ADAMS Accession No. ML13298A625), and April 14, 2015 (ADAMS Accession No. ML15096A391), the NRC staff issued an ISE and audit report, respectively, 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 July 20, 2015 (ADAMS Accession No. ML15205A342), Dominion submitted its compliance letter for Surry, Unit Nos 1 and 2, 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 SE provides the results of the NRC staff's review of Dominion's strategies for Surry. The intent of the SE is to inform Dominion on whether or not its integrated plans, if implemented as described, provide a reasonable path for compliance with 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. ML14273A444). This inspection will be conducted in accordance with the NRC's inspection schedule for the plant.

If you have any questions, please contact Milton Valentin, Orders Management Branch, Surry Power Station Project Manager, at 301-415-2864 or at Milton.Valentin@nrc.gov.

Sincerely,
/RA/
Mandy Halter, Acting Chief
Orders Management Branch
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Office of Nuclear Reactor Regulation

Docket Nos.: 50-280 and 50-281
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ADAMS Accession No. ML16158A432 ***via email**

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