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

May 16, 2016

Mr. David B. Hamilton
Site Vice President
FirstEnergy Nuclear Operating Company
Perry Nuclear Power Plant
Mail Stop A-PY-A290
P.O. Box 97, 10 Center Road
Perry, OH 44081

SUBJECT: PERRY NUCLEAR POWER PLANT, UNIT 1 – SAFETY EVALUATION REGARDING IMPLEMENTATION OF MITIGATING STRATEGIES AND RELIABLE SPENT FUEL INSTRUMENTATION RELATED TO ORDERS EA-12-049 AND EA-12-051 (CAC NOS. MF0962 AND MF0802)

Dear Mr. Hamilton:

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

By letter dated February 27, 2013 (ADAMS Accession No. ML13064A243), FirstEnergy Nuclear Operating Company (FENOC, the licensee) submitted its Overall Integrated Plan for Perry Nuclear Power Plant (PNPP), Unit 1, in response to Order EA-12-049. By letter dated September 25, 2014 (ADAMS Accession No. ML14268A214), FENOC submitted a revised OIP for PNPP that incorporated several significant strategy changes from the original OIP. At six month intervals following the submittal of the original OIP, the licensee submitted reports on its progress in complying with Order EA-12-049. These reports were required by the order, and are listed in the attached safety evaluation. By letter dated August 28, 2013 (ADAMS Accession No. ML13234A503), the NRC notified all licensees and construction permit holders that the staff is conducting audits of their responses to Order EA-12-049 in accordance with NRC Office of Nuclear Reactor Regulation (NRR) Office Instruction LIC-111, "Regulatory Audits" (ADAMS Accession No. ML082900195). By letters dated January 22, 2014 (ADAMS Accession No. ML13338A460) and June 1, 2015 (ADAMS Accession No. ML15098A056), the NRC issued an Interim Staff Evaluation (ISE) and audit report, respectively, on the licensee's progress. By letter dated August 20, 2015 (ADAMS Accession No. ML15232A594, a publicly-available version is available at ADAMS Accession No. ML15362A497), FENOC submitted a compliance letter and Final Integrated Plan (FIP) in response to Order EA-12-049. The compliance letter stated that the licensee had achieved full compliance with Order EA-12-049. By letter dated February 3, 2016 (ADAMS Accession No. ML16036A310), FENOC submitted a revision to the

FIP for Order EA-12-049. By letter dated May 6, 2016 (ADAMS Accession No. ML16127A454), FENOC submitted further supplemental information regarding the the FIP for Order EA-12-049.

By letter dated February 27, 2013 (ADAMS Accession No. ML13059A495), FENOC submitted it's OIP for PNPP in response to Order EA-12-051. At six month intervals following the submittal of the OIP, the licensee submitted reports on its progress in complying with Order EA-12-051. These reports were required by the order, and are listed in the attached safety evaluation. By letters dated November 6, 2013 (ADAMS Accession No. ML13340A653) and June 1, 2015 (ADAMS Accession No. ML15098A056), the NRC 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 June 2, 2015 (ADAMS Accession No. ML15154B199), FENOC submitted a compliance letter and FIP in response to Order EA-12-051. The compliance letter stated that the licensee had achieved full compliance with Order EA-12-051.

The enclosed safety evaluation provides the results of the NRC staff's review of FENOC's strategies for PNPP. The intent of the safety evaluation is to inform FENOC on whether or not its integrated plans, if implemented as described, will adequately address the requirements of Orders EA-12-049 and EA-12-051. The staff will evaluate implementation of the plans through inspection, using Temporary Instruction 191, "Implementation of Mitigation Strategies and Spent Fuel Pool Instrumentation Orders and Emergency Preparedness Communications/Staffing/ Multi-Unit Dose Assessment Plans" (ADAMS Accession No. ML14273A444). This inspection will be conducted in accordance with the NRC's inspection schedule for the plant.

If you have any questions, please contact Peter Bamford, Project Manager, Japan Lessons-Learned Orders Management Branch, at 301-415-2833, or at Peter.Bamford@nrc.gov.

Sincerely,

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

Docket No.: 50-440

Enclosure:
Safety Evaluation

cc w/encl: Distribution via Listserv

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

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

FIRSTENERGY NUCLEAR OPERATING COMPANY

PERRY NUCLEAR POWER PLANT, UNIT 1

DOCKET NO. 50-440

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

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

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

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

On 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. On September 7, 2012, the NRC staff published a notice of the availability of JLD-ISG-2012-01 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.
>
> 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. On September 7, 2012, the NRC staff published a notice of the availability of JLD-ISG-2012-03 in the *Federal Register* (77 FR 55232).

3.0 TECHNICAL EVALUATION OF ORDER EA-12-049

By letter dated February 27, 2013 [Reference 10], FirstEnergy Nuclear Operating Company (FENOC, the licensee) submitted its Overall Integrated Plan (OIP) for Perry Nuclear Power Plant, Unit 1 (PNPP, Perry) in response to Order EA-12-049. By letter dated September 25, 2014 [Reference 11], FENOC submitted a revised OIP for PNPP that incorporated several significant strategy changes from the original OIP. By letters dated August 26, 2013 [Reference 12], February 27, 2014 [Reference 13], August 28, 2014 [Reference 14] and February 26, 2015 [Reference 15], the licensee submitted six-month updates to the OIP. By letter dated August 28, 2013 [Reference 16], 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" (Agencywide Documents Access and Management System (ADAMS) Accession No. ML082900195). By letters dated January 22, 2014 [Reference 17], and June 1, 2015 [Reference 18], the NRC issued an Interim Staff Evaluation (ISE) and an audit report on the licensee's progress. By letter dated August 20, 2015 [Reference 19], the licensee reported that full compliance with the requirements of Order EA-12-049 was achieved, and submitted a Final Integrated Plan (FIP). By letter dated February 3, 2016 [Reference 52], FENOC submitted a revision to the FIP. By letter dated May 6, 2016 [Reference 58], FENOC submitted further supplemental information regarding the the FIP for Order EA-12-049.

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 ultimate heat sink. Thus, the ELAP with loss of normal access to the ultimate heat sink 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 shutdown 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.

Perry (Unit 1) is a General Electric boiling-water reactor (BWR) Model 6 with a Mark III containment. A second unit at the site (Unit 2) was originally planned and was partially constructed; however, it was never completed. References in this safety evaluation to Unit 2 structures, systems and components (SSCs) reflect the licensee's use of such pre-existing SSCs within their overall FLEX strategy for Unit 1, as justified in their plan and evaluated herein.

The licensee's three-phase approach to mitigate a postulated ELAP event, as described in the FIP, is summarized as follows.

At the onset of an ELAP, the reactor trips and the main condenser is unavailable due to the loss of circulating water. Decay heat is removed when the safety relief valves (SRVs) open on high pressure and dump steam from the reactor pressure vessel (RPV) to the Suppression Pool. In this initial phase (Phase 1) all of the core decay heat and RPV sensible heat is deposited to the Suppression Pool. Make-up to the RPV is provided by the reactor core isolation cooling (RCIC) turbine-driven pump, taking suction from the Condensate Storage Tank (CST) if available, or from the Suppression Pool if the CST is not available. Operators use the SRVs to perform a controlled cooldown and depressurization of the reactor. The cooldown of the primary system is stopped when reactor pressure reaches approximately 200 pounds per square inch gauge (psig) (150 to 250 psig operating range) to ensure sufficient steam pressure to operate RCIC and to limit heat discharge to the Suppression Pool. The licensee has performed an engineering evaluation of the RCIC system to demonstrate that the system is robust for all temperatures of the Suppression Pool that are expected during an ELAP event with a loss of normal access to the ultimate heat sink. Since the Suppression Pool temperature increases as it absorbs the heat rejected from the RPV, the licensee has established provisions to establish an alternative supply of cold water to the RCIC pump suction to support operation of the RCIC pump in Phase 2.

During Phase 2, heated water is pumped from the Suppression Pool to the Residual Heat Removal (RHR) system back to the Suppression Pool using either the Suppression Pool Clean Up (SPCU) or Alternate Decay Heat Removal (ADHR) pump (repowered by FLEX generators). This provides a modified RHR Suppression Pool Cooling (SPC) flow path called Suppression

Pool Closed Loop Cooling (SPCLC). Additional coping time may be achieved by dumping the Upper Containment Pool to the Suppression Pool. This is accomplished by opening two motor operated valves when FLEX power is provided to either the Division 1 or 2 480 VAC busses. In the event that the CST is not available and the Suppression Pool cannot be maintained less than 185 degrees Fahrenheit (°F), a hose connection is provided on the RCIC suction. This allows the RCIC suction to be connected to a new Fuel Pool Cooling and Cleanup (FPCC) return header connection. Alternate sources of water to the RCIC alternate suction include the SPCU or ADHR pumps with water through the RHR heat exchangers (HXs) (described above), or the Mix Bed / Two bed demineralized water tanks, if available.

Since the only robust water source installed at PNPP is the Suppression Pool, a long-term alternate source of water is described in the licensee's FIP for a Phase 2 water supply. This source is water from Lake Erie, the UHS, which is supplied by a FLEX generator powered FLEX Lake Water pump deployed in the Emergency Service Water Pump House (ESWPH). This pump takes suction on the ESWPH Suction Bay via the Unit 2 ESW pump pedestal foundation. This is designed to provide 2500 to 3000 gallons per minute (gpm) flow into the ESW system. From this total flow, approximately 1500 to 2000 gpm will be used to supply the RHR HXs in Phase 2, approximately 250 gpm will be available to supply SFP make-up requirements, and approximately 250 gpm (average) will be available for use in the RCIC system to provide a robust alternative water source. The licensee's FIP further describes that provisions have been made to use other water sources of higher quality, if available.

Phase 3 strategies are intended to result in indefinite coping with respect to the required key safety functions. During Phase 3, additional National SAFER Response Center (NSRC) 4160 Vac generators will be connected to the distribution center located in FLEX Equipment Bay 1 (Diesel Generator Building) to supply additional electrical capacity. This additional capacity will allow the start of an RHR pump for use in SPC or Shutdown Cooling (SDC) modes of operation. The additional electrical capacity also allows for additional flow to the ESW loops to be established by providing power to the "N+1" FLEX Lake Water pump.

PNPP has a Mark III containment. During Phase 1, normal design features of the containment, combined with closure of three manual valves, maintains containment integrity. Containment heat removal and hydrogen igniter operation are not possible during Phase 1 since they both rely on the availability of ac power, which is provided in Phase 2. During Phase 2, active cooling of the Suppression Pool will begin. Containment integrity is maintained by keeping containment atmospheric pressure less than the design limit of 15 psig.

To maintain SFP cooling capabilities, the required action is to establish the water injection lineup before the environment on the SFP operating deck degrades due to boiling in the pool. The pool will initially heat up due to the unavailability of the normal cooling system. The licensee has calculated that for the normal pool heat load, boiling could start at about 11 hours after the start of the ELAP. To assist ventilation and prevent over-pressurizing the fuel handling building (FHB), doors from the FHB to the outside on the east side of the plant will be opened prior to boiling. To make up to the SFP, the licensee has established methods to fill from a location external to the pool area, using hoses and/or spray. The fill from the external location and hoses are capable of making up for losses due to boil off and the spray is capable of providing 250 gpm. To support these methods, starting in Phase 2, flow to the ESW system will be provided by a FLEX Lake Water pump, as previously described.

Below are specific details on the licensee's strategies to restore or maintain core cooling, containment, and SFP cooling capabilities in the event of a BDBEE and the results of the staff's review of these strategies. The NRC staff evaluated the licensee's strategies against the endorsed NEI 12-06, Revision 0 guidance, consistent with the licensee's FIP submittals.

3.2 Reactor Core Cooling Strategies

In accordance with Order EA-12-049, licensees are required to maintain or restore cooling to the reactor core in the event of an ELAP concurrent with a loss of normal access to the ultimate heat sink. 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/loss of normal access to the ultimate heat sink) 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.

As reviewed in this section, the licensee's core cooling analysis for the ELAP/loss of normal access to the ultimate heat sink event presumes that, per endorsed guidance from NEI 12-06, the reactor would have been operating at full power prior to the event and that no additional random failures occur. Therefore, primary containment integrity is being credited by the licensee, and the nominal Suppression Pool liquid volume during power operation is assumed to be available as a heat sink for core cooling. Maintenance of sufficient RPV inventory, despite blowdown from SRVs and the 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 event are discussed in further detail below. The licensee's strategy for ensuring compliance with Order EA-12-049 for conditions in which the reactor is shut down or being refueled is reviewed separately in Section 3.11 of this safety evaluation.

3.2.1 Core Cooling Strategy and RCS Make-up

3.2.1.1 Core Cooling Strategy

3.2.1.1.1 Phase 1

Phase 1 of the core cooling strategy relies on the use of installed plant equipment. Injection of cooling water into the RPV will be accomplished through the RCIC system. The RCIC system is initially lined up to the CST and will pump water into the core from the CST, if the CST is available. If the CST is not available, the RCIC pump suction will be re-aligned to the Suppression Pool.

The RCIC pump's design-basis function is to supply water to the RPV when the reactor is isolated from the main condenser. The RCIC pump is powered by steam from the RPV and is robust for the hazards considered in the ELAP evaluation. The RCIC pump is designed to automatically start when the RPV reaches the "Low Level 2" initiation signal. In the event that RCIC does not automatically start, procedural guidance is given for the operators to manually initiate pump operation from the control room or to locally start the pump from the RCIC room. The RCIC discharges into the RPV head cooling spray nozzle. The RCIC system valves are powered by the 125 Vdc Bus and are used to control the cooling flow to the RPV, balancing it with the outflow of steam through the SRVs to the Suppression Pool in order to maintain RPV level within its desired control band.

Pressure control of the RPV is accomplished using the SRVs. The SRVs are powered by redundant logic fed by 125 Vdc Buses. The RPV pressure control band and operation of the SRVs are established to minimize valve cycling in order to preserve adequate battery charge until ac power to the battery chargers is restored. As the RPV is being depressurized, the SRVs are controlled to maintain the cooldown rate less than 100°F per hour. The operators will then stabilize the RPV pressure at around 200 psig to continue to provide adequate steam to support operation of the RCIC turbine.

3.2.1.1.2 Phase 2

In phase 2, RCIC will continue to provide core cooling until it becomes necessary to swap to FLEX cooling. The SRVs will be powered in Phase 2 by the FLEX turbine generators (TGs) and will continue to provide pressure relief. Section 3.2.2.6 of this safety evaluation provides a more detailed description of these TGs. Operation of the FLEX TGs will also ensure that power is continued to the RCIC valves for control of RCIC pump flow.

The licensee's plan for PNPP is to operate the RCIC pump as the motive force for core cooling as long as possible. Water from the Suppression Pool, or from non-robust clean sources of available water will be used preferentially, vice injecting raw lake water into the core. If the Suppression Pool cannot be maintained less than 185°F, a hose connection is provided for the RCIC suction from the FPCC Return header connection in the Auxiliary Building via one of two dry standpipes that run in the Auxiliary Building. Thus, clean or raw water can be provided to the suction of the RCIC pump, depending on water source availability.

The ESWPH pump suction bay allows for the FLEX Lake Water pumps to take suction from Lake Erie. The pumps are designed to provide 2500 to 3000 gpm into the ESW system, of which, 1500 to 2000 gpm will be used to supply the RHR HXs, about 250 gpm will be used to provide SFP cooling, and about 250 will be provided to the RCIC system as a water source if necessary. Either the SPCU or the ADHR pumps are used to pump water from the Suppression Pool to the RHR system and back to the Suppression Pool, providing cooling to the Suppression Pool volume.

According to the licensee's FIP, the SPCU or ADHR pumps can supply water through the RHR HXs back to the Suppression Pool or to the RPV through RCIC. Mix Bed/Two Bed tanks can be used to supply RCIC as an alternate, if available. Either ESW trains "A" or "B" can supply RCIC with lake water as a robust long term water supply.

In the event that RCIC is no longer available, the RPV pressure will be lowered to allow for low pressure injection with FLEX equipment or other installed systems. High Pressure Core Spray (HPCS) and Low Pressure Core Spray (LPCS) contain flush connections that will allow for injection points. The HPCS system has a Storz connection used for Fast Firewater (a 5-inch Storz connection is available to the HPCS system to route FLEX Lake Water pump discharge to the RPV as an injection source of water) and the LPCS line has been modified to accept a standard fire hose for low pressure injection. Either of those connection points can be used for RPV injection during ELAP conditions. The ESW "A" and "B" systems have Storz connections on them and they are designed to provide approximately 1000 gpm to the HPCS or LPCS systems. These systems can be aligned via hose to the various connections.

3.2.1.1.3 Phase 3

The Phase 3 strategy includes the use of equipment from the NSRC. The plant plans to continue the use of phase 2 equipment or replace as necessary. When the Phase 3 equipment arrives on site, the licensee plans to use additional 4160 Vac generators to supply power that would allow the start of an RHR pump for the use in Suppression Pool Cooling or SDC modes of operation. The additional electrical capacity will provide the capability to place in service the additional "N+1" FLEX Lake Water pump to supply increased cooling flow to the RHR system heat exchangers, if needed. The SDC mode of RHR would allow the plant to achieve a cold condition using the lake water as the ultimate heat rejection source.

Alternatively, the Suppression Pool could be cooled using the SPC mode of RHR, cooling the Suppression Pool, and rejecting the heat through the RHR HXs to the ESW system. In this situation, the RCIC pump could still be in operation until the decay heat levels are so low that they no longer support the RCIC turbine operation.

3.2.2 Staff Evaluations

3.2.2.1 Availability of Structures, Systems, and Components

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

3.2.2.1.1 Plant SSCs

NEI 12-06, Section 3.2 states that installed equipment that is designed to be robust with respect to design-basis external events is assumed to be fully available. In addition, 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. The PNPP Updated Final Safety Analysis Report (UFSAR), Section 3.2.1, [Reference 51], states that plant SSCs important to safety are designed to withstand the effects of a safe-shutdown earthquake (SSE), that SSCs (including their foundations and supports) designed to remain functional in the event of an SSE are designated as Seismic Category I, and that SSCs designated as Safety Class 1, Safety Class 2 or Safety Class 3 are classified as Seismic Category I. The PNPP UFSAR, Section 3.4.2, states that the Safety Class I structures (i.e. Seismic Category I) will not be subjected to flood current, wind, wave, hurricane, tsunami, seiche, or dynamic water forces. In addition, UFSAR Section 3.5.1.4.2 states that the exterior walls and roof of Seismic Category I structures are required to withstand the effects of the design-basis tornado, including tornado missiles.

The licensee's core cooling FLEX strategies rely on its existing RCIC to remove heat from the reactor by providing cooling water to the RPV from the Suppression Pool and relieving pressure from the RPV through the relief valves (SRV's). In addition, the licensee relies on Class IE batteries and the dc distribution system, and, for Phase 2 core cooling, the upper containment pool, the UHS, ESW (including intake, discharge, and pump house), the RHR system, the SPCU pump, the ADHR pump, the HPCS system, and the LPCS system.

As described in the PNPP UFSAR, Table 3.2-1, Revision 12, the RCIC system including piping, equipment, and support structures, is designed to Seismic Category I standards. As described in the licensee's FIP, the RCIC pump is located in the Auxiliary Building which is Seismic Category I, and protected against seismic events, floods, and high winds. The pump and supporting valves and piping are also seismically qualified. The RCIC system valves are powered by 125 Vdc Bus ED1A. According to the UFSAR, Table 3.2-1, Revision 12, the 125 Vdc power system (which is located in the control building complex) that supports safety functions is designed as Seismic Category I. In addition, the licensee indicated that if the automatic start does not occur, the controlling procedures provide guidance to the operator to manually initiate the RCIC system or to take action to locally start the system from the RCIC room.

As described in the licensee's FIP, the RCIC pump takes suction initially from the CST and operates to inject make-up water to the RPV. The CST is not seismically qualified and it is considered unavailable following a BDBEE. However, the CST is protected by a dike that is seismically and missile hazard qualified. Upon failure of the CST during an event, the volume of water that was in the CST at the time of failure is contained within the dike area. For some external events, such as flooding and all but the most catastrophic failures of the CST, the CST could be available for a period time to supply the RCIC system. If the CST is not available for use, the operators align RCIC suction to the suction from the Suppression Pool per existing operations procedure(s). In addition to the suction source for the RCIC pump, the Suppression Pool is the heat sink for reactor vessel SRV discharge and RCIC turbine steam exhaust following a BDBEE. The PNPP UFSAR, Table 3.2-1, describes the Suppression Pool, which is part of the Reactor Building complex, as a Seismic Category I structure.

Operators relieve pressure from the RPV through the SRV's. As described in the PNPP UFSAR, Table 3.2-1, the SRV's are designed as Seismic Category I. According to the licensee's FIP, operators control the RPV pressure using the Automatic Depressurization System (ADS) SRVs by electric operation of the valves. The ADS SRVs logic power comes from redundant power supplies off 125 Vdc Bus ED1A and 125 Vdc Bus ED1B. According to the PNPP UFSAR, Table 3.2-1, the 125 Vdc power system (including 125 Vdc batteries, racks, chargers, and distribution equipment) that supports safety functions is designed as Seismic Category I.

For Phase 2 core cooling, the licensee plans to continue using RCIC (when the RPV is pressurized above approximately 60 psig) to provide high-pressure core cooling as it had in Phase 1. As the RCIC suction water temperature from the Suppression Pool heats up over 140°F, the licensee will switch the RCIC suction to a cooler water source. A tap is provided at the discharge of the RHR HXs that can be connected to the tap on the RCIC suction line. The SPCU or ADHR pumps will therefore supply Suppression Pool water through the RHR HXs to the RCIC suction. The secondary side of the RHR HXs are fed cooling water from the UHS via a FLEX Lake Water pump through the ESW system.

According to the PNPP UFSAR, Table 3.2-1, the RHR HXs, RHR piping and valves, ESW piping and valves, ESW, pump house, intake structure and tunnels, and discharge tunnels are Seismic Category I components and/or structures. According to the licensees FIP, the SPCU and ADHR systems were evaluated to meet the definition of "robust" per NEI 12-06. The SPCU pump was evaluated under the Expedited Seismic Evaluation Process (ESEP). This evaluation process concluded that the SPCU pump exhibited a high confidence of low probability of failure when subjected to the reevaluated seismic hazard for the site. Thus, it is reasonable to conclude that the pump would be available and able to perform its function following a seismic event. Section 5.5.3.7 of the licensee's reference document, NORM-LP-7302, "FLEX Mechanical Design Report for the Perry Nuclear Power Plant," Revision 0, states that the ADHR system is a non-safety related system, but was designed and installed with seismic loading requirements. It concludes that the ADHR system is robust for all applicable external hazards because it is seismically qualified and located within a safety-related structure. For the seismic qualification of the SPCU discharge piping, the licensee performed a pipe stress calculation, 1G42G001A, "Piping Stress Analysis: Discharge Piping from Pump 1G42C0001 to Subsystem 1G41G007A," Revision 0. This calculation concluded that, with some support modifications, the SPCU piping met the appropriate stress criteria to be deemed robust in accordance with the definition of NEI 12-06.

If RCIC operation is not available, the operators will lower RPV pressure to allow the FLEX Lake Water pump to inject into the RPV via the ESW system to either the LPCS or HPCS discharge piping. According to PNPP UFSAR, Table 3.2-1, the LPCS, HPCS and ESW systems are classified as Seismic Category I. These systems are located primarily in the Auxiliary Building and ESW Pump House, which are structures protected against all applicable external events.

Based on the location and design of the credited plant SSCs, as described in FENOC's UFSAR, and if implemented according to the licensee's control strategy, as described in the FIP, the NRC staff concludes that the credited plant SSCs should be available to support core cooling during an ELAP, consistent with NEI 12-06, Section 3.2.1.3, Condition 6.

3.2.2.1.2 Primary and Alternate Connection Points for Core Cooling

Section 3.2.2 of NEI 12-06 states that the portable pumps for core and SFP cooling functions are expected to have a primary and an alternate connection or delivery point. At a minimum, the primary connection point should be an installed connection suitable for both the on-site and off-site equipment, but the secondary connection point can require reconfiguration if the licensee can show that adequate time and resources are available to support the reconfiguration. In accordance with Section 3.2.2 of NEI 12-06, the licensee has a primary and alternate method for providing cooling water to the RPV.

The licensee provides water from the UHS via the FLEX Lake Water pump and portable hoses into the ESW system. From the ESW system, water can be delivered to the RCIC suction, or the LPCS or HPCS systems for core cooling via dry stand pipes and portable hoses inside the Auxiliary Building. The primary ESW flow path is through ESW "A" Loop. The licensee installed three 5-inch Storz connection points on the ESW "A" pump discharge piping to allow a FLEX Lake Water Pump to be connected to the ESW "A" Loop. The connections are located inside the ESW pump house between the ESW "A" Pump discharge check valve and the discharge strainer. The alternate ESW flow path is through ESW "B" Loop. The licensee installed three 5-inch Storz connection points on the ESW "B" pump discharge piping to allow either of the two FLEX Lake Water Pumps to be connected to the ESW "B" Loop. The connections are located inside the ESW pump house between the ESW "B" Pump discharge check valve and the discharge strainer. In addition, the licensee installed a new 5-inch Storz connection on the ESW "A" and ESW "B" system piping inside the auxiliary building to provide water from the ESW system to the HPCS or LPCS systems via the installed dry standpipes.

The HPCS system has a previously installed 5-inch Storz connection on the HPCS pump discharge piping. The LPCS has a flush line similar to the HPCS connection, which the licensee has modified to accept a standard fire hose for low-pressure vessel injection. Either of these connection points can be aligned to ESW "A" or "B" systems for RPV injection via one of two dry standpipes installed in the Auxiliary Building.

Based on the location and design of the FLEX connections, as described in FENOC's FIP, and if implemented according to the licensee's control strategy, as described in the FIP, at least one FLEX connection should be available to support core cooling during an ELAP, consistent with NEI 12-06, Section 3.2.2 and Table C-1.

3.2.2.1.3 <u>Plant Instrumentation</u>

The licensee's plan for PNPP is to monitor instrumentation in the control room. The instrumentation is powered by batteries and will be maintained for indefinite coping via battery chargers powered by the FLEX Diesel TGs. A more detailed evaluation of the instrumentation power supply is contained in Section 3.2.2.6 of this safety evaluation.

As described in FENOC's FIP for PNPP, instrumentation for the following parameters is credited for all phases of core cooling and RPV inventory control:

- RPV Level
- RPV Pressure

The instrumentation identified by the licensee to support its core cooling strategy is consistent with the recommendation specified in the endorsed guidance of NEI 12-06. This instrumentation is available both prior to and after AC and DC busses load shedding. Availability in Phase 2 and Phase 3 will be maintained by successfully implementing the overall battery charging FLEX strategy. Furthermore, the NRC staff understands that the locations of the instrument indications would be accessible continuously throughout the ELAP event.

In accordance with NEI 12-06 Section 5.3.3.1, guidelines for obtaining critical parameters locally are provided in an FSG. Should it be required, the licensee will use guidance that provides a list of key parameters, locations, and equipment needed to obtain local readings of key parameters. Flex Support Guideline (FSG) 90.1, "Reading Instruments via Measuring and Test Equipment," Revision 0, was reviewed during the audit to verify this plan.

3.2.2.2 Thermal-Hydraulic Analyses

The licensee concluded that its mitigating strategy for reactor core cooling would be adequate based in part on thermal-hydraulic analysis performed using Version 4 of the Modular Accident Analysis Program (MAAP). Because the thermal-hydraulic analysis for the reactor core and containment during an ELAP event are closely intertwined, as is typical of BWRs, the licensee has addressed both in a single, coupled calculation. This dependency notwithstanding, the NRC staff's discussion in this section of the safety evaluation solely focuses on the licensee's analysis of reactor core cooling. The review of the licensee's analysis of containment thermal-hydraulic behavior is provided in Section 3.4.4.2 of this evaluation.

The MAAP is an industry-developed, general-purpose thermal-hydraulic computer code that has been used to simulate the progression of a variety of light water reactor accident sequences, including severe accidents such as the Fukushima Dai-ichi event. Initial code development began in the early 1980s, with the objective of supporting an improved understanding of and predictive capability for severe accidents involving core overheating and degradation in the wake of the accident at Three Mile Island Nuclear Station, Unit 2. Currently, maintenance and development of the code is carried out under the direction of the Electric Power Research Institute (EPRI).

To provide analytical justification for their mitigating strategies in response to Order EA-12-049, a number of licensees for BWRs and pressurized-water reactors (PWRs) completed analysis of the ELAP event using Version 4 of the MAAP code (MAAP4). Although MAAP4 and predecessor code versions have been used by industry for a range of applications, such as the analysis of severe accident scenarios and probabilistic risk analysis (PRA) evaluations, the NRC staff had not previously examined the code's technical adequacy for performing best-estimate simulations of the ELAP event. In particular, due to the breadth and complexity of the physical phenomena within the code's calculation domain, as well as its intended capability for rapidly simulating a variety of accident scenarios to support PRA evaluations, the NRC staff observed that the MAAP code makes use of a number of simplified correlations and approximations that should be evaluated for their applicability to the ELAP event. Therefore, in support of the reviews of licensees' strategies for ELAP mitigation, the NRC staff audited the capability of the MAAP4 code for performing thermal-hydraulic analysis of the ELAP event for both BWRs and PWRs. The NRC staff's audit review involved a limited review of key code models, as well as confirmatory analysis with the TRACE code to obtain an independent assessment of the predictions of the MAAP4 code.

To support the NRC staff's review of the use of MAAP4 for ELAP analyses, in June 2013, EPRI issued a technical report entitled "Use of Modular Accident Analysis Program (MAAP) in Support of Post-Fukushima Applications." The document provided general information concerning the code and its development, as well as an overview of its physical models, modeling guidelines, validation, and quality assurance procedures.

Based on the NRC staff's review of EPRI's June 2013 technical report, as supplemented by further discussion with the code vendor, audit review of key sections of the MAAP code documentation, and confirmation of acceptable agreement with NRC staff simulations using the TRACE code, the NRC staff concluded that, under certain conditions, the MAAP4 code may be used for best-estimate prediction of the ELAP event sequence for BWRs. The NRC staff issued an endorsement letter dated October 3, 2013 [Reference 53], which documented these conclusions and identified specific limitations that BWR licensees should address to justify the applicability of simulations using the MAAP4 code for demonstrating that the requirements of Order EA-12-049 have been satisfied.

During the audit process, the NRC staff verified that the licensee's MAAP calculation, along with an associated addendum, addressed the limitations from the NRC staff's endorsement letter. The licensee utilized the generic roadmap and response template that had been developed by EPRI to support consistency in individual licensee's responses to the limitations from the endorsement letter. In particular, based upon review of the MAAP calculation documentation, the staff concluded that appropriate inputs and modeling options had been selected for the code parameters expected to have dominant influence for the ELAP event. The NRC staff further observed that the limitations imposed in the endorsement letter, particularly those concerning the RPV collapsed liquid level being maintained above the reactor core and the primary system cooldown rate being maintained within Technical Specification limits, were satisfied. Specifically, the licensee's analysis calculated that PNPP would maintain the collapsed liquid level in the reactor vessel at least 10 feet above the top of the active fuel region throughout the analyzed ELAP event. By maintaining the reactor core fully covered with water, adequate core cooling is assured for this event. Additionally, PNPP's fulfillment of the endorsement letter condition regarding the primary system cooldown rate signifies that thermally induced volumetric contraction and other changes in primary system thermal-hydraulic conditions should proceed relatively slowly with time, which supports the NRC staff's confidence in the predictions of the MAAP code. Furthermore, that the licensee should be capable of maintaining the entire reactor core submerged throughout the ELAP event is consistent with the staff's expectation that the licensee's flow capacity for primary makeup (i.e., installed RCIC pump and, subsequently, FLEX pumps) should be sufficient to support adequate heat removal from the reactor core during the analyzed ELAP event, including potential losses due to expected primary leakage.

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

3.2.2.3 Recirculation Pump Seals

An ELAP event would result in the interruption of cooling to the recirculation pump seals, potentially resulting in increased leakage due to the distortion or failure of the seals, elastomeric o-rings, or other components. Sufficient primary make-up must be provided to offset recirculation pump seal leakage and other expected sources of primary leakage, in addition to removing decay heat from the reactor core.

The licensee's calculations assumed a seal leakage rate at full system pressure and temperature of 18 gpm per recirculation pump. In addition, the licensee's calculation assumed an additional primary system leakage rate equal to the Technical Specification limit (averaged over the previous 24-hour period) of 30 gpm. Thus, between the two recirculation pumps and the additional primary system leakage, the total primary leakage rate assumed during the ELAP event was 66 gpm at full system pressure and temperature.

PNPP has Byron Jackson recirculation pumps with Flowserve N-7500 seals. The Flowserve N-7500 seals installed on the recirculation pumps are similar in design to the N-Seals for which the NRC staff has reviewed and endorsed leakage rates for application to the ELAP event for specific PWRs. As noted in the NRC staff's endorsement letter on this topic, dated November 12, 2015 [Reference 50], the upper bound leakage rates under ELAP conditions that have been estimated for Flowserve N-Seals installed at PWRs vary based on plant-specific conditions, but are in all cases less than 5 gpm. Among the noteworthy differences between the N-Seals installed at BWRs and PWRs are that current BWR installations: (1) rely on a reduced number of stages due to the lower BWR operating pressure, (2) are scaled-down geometrically compared to most PWRs, according to differences in pump shaft size, and (3) do not provide for the possibility of isolating the controlled leakoff flow from the seal, as is possible for some PWRs. However, the NRC staff does not expect these differences to have a significant impact on the expected seal leakage rate for BWR applications because (1) the design of each seal stage is intended to be capable of sealing against full system pressure, and, furthermore, the vendor's method for determining the leakage rate for PWRs was not dependent upon the number of stages in the seal design, (2) the staff's review of Flowserve's determination of the expected N-Seal leakage for PWRs explicitly considered pump shaft sizes for which the N-7500 model would be applicable, and (3) credit for isolation of the controlled seal leakoff flow was not explicitly credited in determining the leakage rates determined in Flowserve's white paper, with the exception of determining the short-term thermal exposure profile for seal elastomers. Thus, even while considering the differences between BWR and PWR installations, based on the basic design of the hydrodynamic seals and pressure breakdown devices and their materials of construction, the NRC staff would expect a roughly similar level of performance for equivalent inlet conditions.

The NRC staff considered the expected leakage rate for the N-7500 seals installed at PNPP in light of experience obtained reviewing the application of N-Seals to PWRs. In particular, the NRC staff noted during its audit of the licensee's thermal-hydraulic analysis that the expected primary temperature and pressure conditions during an ELAP event are consistent with those of the PWRs considered in the staff's endorsement letter. Furthermore, as is typical of the majority of U.S. BWRs, PNPP has an installed steam-driven pump (i.e., RCIC) that is capable of injecting into the primary system under ELAP conditions. Based on information provided by the licensee during the audit, the RCIC system is designed to provide an injection flow of 700 gpm, which significantly exceeds the combined flow requirement to offset boiloff from decay heat, in addition to the expected system leakage. The other pumps used for core cooling in the licensee's FLEX strategy have a similar functional capability. As such the NRC staff finds that: (1) the licensee's assumed recirculation pump seal leakage rate of 18 gpm at full system temperature and pressure appears reasonable for the ELAP event, and (2) substantial margin exists to accommodate primary system leakage rates greater than expected.

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

3.2.2.4 Shutdown Margin Analyses

As described in PNPP's UFSAR, Sections 3.1.2.3.7 and 3.1.2.3.7.1, the control rods provide adequate shutdown margin under all anticipated plant conditions, with the assumption that the highest-worth control rod remains fully withdrawn. PNPP Technical Specification Section 1.1, further clarifies that shutdown margin is to be calculated for a cold, xenon-free condition to ensure that the most reactive core conditions are bounded.

Based on the NRC staff's audit review, the licensee's ELAP mitigating strategy maintains the reactor within the envelope of conditions analyzed by the licensee's existing shutdown margin calculation. Furthermore, the existing calculation retains conservatism because the guidance in NEI 12-06 permits analyses of the beyond-design-basis ELAP event to assume that all control rods fully insert into the reactor core.

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.

3.2.2.5 FLEX Pumps

After RCIC operation is no longer possible, the licensee's credited strategy for core cooling uses submersible FLEX pumps (powered by FLEX TGs), which draw suction from the UHS and discharge into the RPV via the ESW system and the HPCS or LPCS system via portable hoses. In accordance with Section 11.2 of NEI 12-06, the licensee performed Calculation X11-004, "FLEX Hydraulic Flow Model," Revision 0, which analyzed each flow path and determined the pump characteristics needed to provide adequate flow for core cooling. The NRC staff performed a review of Calculation X11-004 and compared the results to the FLEX pump design capacity to ensure that the FLEX pump has sufficient capacity to support the overall strategy. The calculation uses classical hydraulic analysis head loss and pressure gradient methods and includes all pumps, valves, hoses, strainers, elevations, and line distances. Based on design of the FLEX pumps, the results of Calculation X11-004, and if implemented according to the licensee's strategy for core and containment cooling, as described in the FIP, the NRC staff concludes that the FLEX pumps should have sufficient capacity to support core cooling during an ELAP consistent with the provisions of NEI-12-06, Section 11.2.

3.2.2.6 Electrical Analyses

The licensee's FIP describes strategies capable of mitigating a simultaneous loss of ac power and loss of normal access to the ultimate heat sink resulting from a BDBEE by providing the capability to maintain or restore core cooling (the licensee's strategy for inventory control uses the same electrical strategy as for maintaining or restoring core cooling), containment, and spent fuel pool cooling. Furthermore, the electrical coping strategies are the same for all modes of operation.

The NRC staff reviewed the licensee's FIP to determine whether, if implemented appropriately, the licensee's strategies should be able to maintain or restore core cooling, containment, and spent fuel pool cooling following a BDBEE. The NRC staff reviewed conceptual electrical single-line diagrams, summaries of calculations for sizing the FLEX TGs 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 as a result of a BDBEE. According to the licensee's FIP, ELAP entry conditions can be verified by control room staff. As stated in the FIP, a transition to ONI-R10-2, "Total Loss of AC Power," will be made upon the diagnosis of the total loss of ac power. This procedure directs isolation of primary containment systems, reduction of dc loads on the station Class 1E batteries, and establishes electrical equipment alignment in preparation for eventual power restoration.

The NRC staff reviewed the electrical portion of the mitigation strategy for a BDBEE condition with the licensee's staff and performed a walk-down of the licensee's strategies during an onsite audit that was conducted on December 16-19, 2014 [Reference 18]. The walk-down focused of the areas where the FLEX portable electrical equipment will be located, the connection points to the electrical distribution system, battery load shedding, and the cable runs from the staged and deployed FLEX turbine generators (TGs) to the installed equipment.

The Phase 1 FLEX strategy involves relying on installed plant equipment and onsite resources such as use of installed Class 1E station batteries and switchgear. The installed equipment is located in structures considered robust and protected with respect to seismic events, high winds, and associated missiles. Procedure ONI-SPI D-3 provides guidance to cross-tie Unit 1 and Unit 2 station batteries in each division within 30 minutes of the start of the ELAP event. Load shedding per ONI-SPI D-2 is also performed such that all circuit breakers of the non-essential loads are opened within three hours of the event. The mission time for the battery bank is extended to greater than 24 hours per the licensee's calculations with the above operator actions. Although Unit 2 is not functional, the licensee maintains the Unit 2 station batteries such that they are able to support Unit 1 operation.

The NRC staff reviewed the summary of the dc system analyses in Calculation PRDC0012, "Evaluate the DC Loads Supplied by the Division 1 & 2 Batteries, 1R42S0002 OR 2R42S0002 AND 1R42S0003 OR 2R42S0003 During an Extended 24 Hour SBO Event," Revision 3, which verified adequacy and capability of the dc system to supply the required Phase 1 of the mitigation strategies plan for an ELAP as a result of a BDBEE. The licensee's analysis identified the required loads and their associated ratings (amperage and minimum voltage), cross-tying Unit 1 and Unit 2 station batteries within 30 minutes of the event per Procedure ONI-SPI D-3, "Cross-Tying Unit 1 and Unit 2 Batteries," and non-essential loads that would be shed within 3 hours of the event per ONI-SPI D-2, "Non-Essential DC Loads," to ensure battery operation for at least 24 hours. According to the licensee's FIP, Table C-1, FLEX TG power is expected to be restored to the battery charger at approximately 6 hours, well within this time frame. Additionally the NRC staff review also determined that the licensee has evaluated the battery coping time consistent with an NEI white paper regarding battery duty cycles, "EA-12-049 Mitigating Strategies Resolution of Extended Battery Duty Cycles Generic Concern," dated August 27, 2013 [Reference 54], which was endorsed by the NRC in a letter dated September 16, 2013 [Reference 55].

To further confirm extended battery duty cycles, 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," [Reference 56]. The purpose of this testing was to examine whether existing vented lead acid batteries can function beyond their defined design basis (or beyond-design basis if existing Station Blackout (SBO) coping analyses were utilized) duty cycles in order to support core cooling. The study evaluated battery performance availability and capability to supply the necessary dc loads to support core cooling and instrumentation requirements for extended periods of time.

The testing provided an indication of the amount of time available (depending on the actual load profile) for batteries to continue to supply dc power to the core-cooling equipment beyond the original duty cycles for a representative plant. The testing also demonstrated that battery availability can be significantly extended using load shedding techniques to allow more time to recover ac power. The testing further demonstrated that battery performance is consistent with battery manufacturing performance data.

Based on information contained in NUREG/CR-7188, and its review of the licensee's analysis, the battery vendor's specifications for the capacity and discharge rates for the batteries, as well as the controlling procedures/guidelines, the NRC staff concludes that the licensee's load shed strategy is acceptable and that the batteries should have sufficient capacity to supply power to the required loads until both battery chargers are reenergized from the FLEX TGs, as discussed below.

According to the licensee's FIP, the Phase 2 strategy involves transition from installed equipment to the onsite FLEX equipment including repowering Class 1E battery chargers. PNPP's on-site electrical FLEX equipment includes two 4160 Vac, 1.1-MegaWatt electric (MWe) FLEX TGs. Both of these generators (2.2 MWe total) are required to provide sufficient electrical power for the expected loads (1.35 MWe or alternatively 1348.5 kilowatts (kW)), including a FLEX Pump in the ESW Pump house, 480 Vac pumps for process flow, Unit 1 and Unit 2 battery chargers, control room and plant essential lighting, essential instruments, installed and portable ventilation, hydrogen igniter operation and motor operated valves. Thus, these two TGs together constitute the "N" set of Phase 2 electrical supply. These FLEX TGs will be stored in the Unit 2 Diesel Generator Building, designated as FLEX Equipment Bay 1. The Unit 2 Diesel Generator Building is a Class 1 structure and is protected from all applicable external hazards. The two FLEX TGs will be moved out of the storage area and deployed outdoors in areas west of the Diesel Generator Building within 3 hours of the ELAP condition, in order to re-power the necessary equipment within 6 hours of the ELAP condition.

The licensee's FIP also describes provisions for an identical third FLEX 1.1 MWe TG, designated as the "N+1", or spare TG. This TG will be stored in the Unit 2 Auxiliary Building east side, designated as FLEX Equipment Bay 2. This location is also protected from all applicable external hazards. Support equipment for the "N+1" TG, including cabling, is stored with the "N+1" FLEX generator.

If any one of the two "N" TGs becomes unavailable or are out of service for maintenance, the "N+1" TG will be deployed to continue to maintain the capability to support the required loads. The "N+1" TG is identical to each of the "N" TGs, thus ensuring electrical compatibility and sufficient electrical capacity in an instance where substitution is required. Since the "N+1" TG is identical and interchangeable with each of the "N" TGs, the NRC staff finds that the licensee has met the provisions of NEI 12-06, Revision 0 for spare equipment capability regarding the Phase 2 TGs.

During the audit process, the NRC staff reviewed key licensee electrical documents including: NORM-LP-7301, "FLEX Electrical Design Report for the Perry Nuclear Power Plant", Revision 0, FLEX TG single line electrical diagrams, and FLEX procedures. The staff review considered the locations of stored, staged and deployed FLEX TGs, protection and diversity of the power supply pathways, separation and isolation of the deployed FLEX TGs from the Class 1E emergency diesel generators, and availability of procedures to direct operators how to align, connect, and protect associated systems and components. Based on that review, the NRC staff finds that the licensee's conclusion that the FLEX TGs have sufficient capacity and capability to supply the necessary loads following a BDBEE is reasonable.

For Phase 3, the licensee plans to continue the Phase 2 coping strategy with additional assistance provided from offsite equipment/resources. Off-site equipment from the NSRCs will arrive on-site by hour 24 and be deployed by hour 26 to support Phase 3 coping capabilities. This includes 4160 Vac TGs capable of re-powering 4160 Vac buses and switchgear through the distribution center. The distribution center is designed to allow the rapid connection and paralleling of multiple generators (it allows up to four generators to be used together) to supply power to the plant electrical system. For Phase 3, the two "N" FLEX Generators thus are supplemented by two NSRC TGs. The licensee concludes that this will provide sufficient electrical capacity (approximately 4 MWe) to allow starting a RHR pump in SDC mode (RHR SDC mode) or in RHR SPC mode. Based upon a review of the licensee's analyses, the NRC staff finds that the Phase 3 equipment will provide adequate capacity to supply the minimum required loads to maintain or restore core cooling, SFP cooling, and containment indefinitely following an ELAP.

3.2.3 Conclusions

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

3.3 Spent Fuel Pool Cooling Strategies

Order EA-12-049 requires that SFP cooling capabilities be maintained or restored as part of an overall strategy to mitigate a BDBEE. NEI 12-06, Section 3.2.1.1 implements this requirement, in part, by establishing a provision to keep fuel in the SFP covered. NEI 12-06, Table 3-1 and Appendix C summarize one acceptable approach for the SFP cooling strategies. This approach uses a portable injection source to provide three (3) baseline capabilities by: 1) make-up via hoses on the refueling floor capable of exceeding the boil-off rate for the design basis heat load; 2) make-up via connection to spent fuel pool 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 to account for overspray). In conjunction with the SFP cooling strategies, each site should provide a strategy to establish a vent pathway to remove steam and condensate from the SFP area.

Section 8.5 of the licensee's FIP states that the SFP is subject to water loss from seismic sloshing and from boil-off due to lack of cooling of the spent fuel decay heat. Pool inventory make-up, at a flow rate of about 100 gpm, is estimated to be required at approximately 26 hours with maximum heat load (following a full core off-load) after the event to ensure that the racks remain covered. To meet guidance in NEI 12-06, Section 3.2.1.1, Table 3-1, and Appendix C, the licensee will provide lake water from the FLEX pumps (via the ESW system) to make up to the SFP

3.3.1 Phase 1

For Phase 1 SFP cooling, the licensee credits the large inventory and heat capacity of the water in the SFP. As described in Section 8.5.1 of the licensee's FIP (Section 3.3.4.2 of this safety evaluation), following the loss of the normal SFP Cooling System, the SFP will slowly heat up and begin to boil. The time required to boil off SFP inventory to a water level of 10 feet above the fuel racks is approximately 122 hours for the normal decay heat load in the pool and 47 hours for the maximum decay heat load in the pool. The licensee's initial coping strategy for SFP cooling is to monitor SFP level using instrumentation installed as required by NRC Order EA-12-051.

3.3.2 Phase 2

As described in Section 8.5.2 of the licensee's FIP, in Phase 2, the SFP will heat to the boiling point and the level in the pool will drop. The licensee calculated the required make-up to maintain level in the SFP to be approximately 33 gpm for the normal heat load case. The licensee will take action to align make-up to the pool using lake water supplied through the ESW pipes to a new make-up header along the west end of the SFP. The FIP, Section 8.5.2, states that make-up will be established such that pool level and cooling will be maintained throughout the event.

In accordance with NEI-12-06, Appendix C, the licensee can provide make-up to the SFP using three (3) different methods: make-up via portable hose over the edge of the pool, make-up using existing piping, and make up via portable pump with hose and spray nozzle using existing strategies required by previous NRC Order EA-02-026, Section B.5.b, and Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Section 50.54(hh)(2).

The licensee has added a 4-inch line with isolation valves on each of the ESW "A" and "B" supply lines that run through the Intermediate Building. These two 4 inch lines come together into a common 4-inch line. This 4-inch line runs along the SFP deck, thereby providing remote pool make-up without access to the Fuel Handling Building. Prior to this piping entering the Fuel Handling Building, isolation valves are installed and hose connections are provided so that pool make-up can also be achieved via either manually routed hoses, or via deployment of hose-supplied portable spray nozzles. Operators can align the fill header once the ESW alignments are completed and the ESW piping is pressurized with the FLEX pumps.

With ESW "A" or "B" train pressurized by the FLEX Lake Water pump in the ESWPH, operators can open one train's isolation valve then open the header shutoff valve, both of which are located on Intermediate Building 599' elevation. The licensee stated that final injection valve is administratively maintained (locked) open and is required to be closed if any type of hose make-up is desired. If operators need to make up to the SFP via hoses, the hose connection isolation valve, which is located in the Unit 2 Annulus Exhaust Gas Treatment System fan room, will need to be opened. This results in a total of four manual valve manipulations for hose applications. In addition, the licensee can use the hose connections, which serve to provide connections for manually routed/deployed hoses and spray nozzles, to inject other water sources into the SFP without accessing the Fuel Handling Building. This provision, although not credited, ensures that raw water injection into the SFP can be delayed as long as practical.

3.3.3 Phase 3

Additional capabilities will be available from the NSRC as a backup to the on-site FLEX equipment. Section 8.5.3 of licensee's FIP, states that the Phase 2 strategy will be continued until the station chooses to restore FPCC using off-site equipment.

3.3.4 Staff Evaluations

3.3.4.1 Availability of Structures, Systems, and Components

The baseline assumptions established in NEI 12-06 presume 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, in general, assumed to be fully available. Installed equipment that is not robust is, in general, assumed to be unavailable. In addition, the base line assumptions established in NEI-12-06 for the SFP allow licensees to presume that all boundaries of the SFP are intact, including the liner, gates, transfer canals, etc., and that SFP cooling system is intact, including attached piping.

3.3.4.1.1 Plant SSCs

NEI 12-06, Section 3.2 states that installed equipment that is designed to be robust with respect to design-basis external events is assumed to be fully available. 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, NEI 12-06, Section 3.2.1.6 states that the assumed initial SFP conditions are: 1) all boundaries of the SFP are intact, including the liner, gates, transfer canals, etc., 2) although sloshing may occur during a seismic event, the initial loss of SFP inventory does not preclude access to the refueling deck around the pool and 3) SFP cooling system is intact, including attached piping. The PNPP UFSAR, Section 3.2.1, states that plant SSCs important to safety are designed to withstand the effects of an SSE, that SSCs (including their foundations and supports) designed to remain functional in the event of an SSE are designated as Seismic Category I, and that designated as Safety Class 1, Safety Class 2 or Safety Class 3 are classified as Seismic Category I. The PNPP UFSAR Section 3.4.2 states that the Safety Class I structures (i.e. Seismic Category I) will not be subjected to flood current, wind wave, hurricane, tsunami, seiche, or dynamic water force. In addition, UFSAR Section 3.5.1.4.2 states that the exterior walls and roof of Seismic Category I structures are required, by definition, to withstand the effects of the design basis tornado including tornado missiles.

Section 8.5 of the licensee's FIP, describes the methods for providing water to the SFP. The SSCs the SFP cooling methods rely on are the ESW "A" and "B", ESW pump house and the intake structure and tunnel. As discussed in Section 3.2.3.1.1 of this evaluation, the ESW piping and valves, ESW, pump house, intake structure and tunnels, and discharge tunnels are Seismic Category I components and/or structures and are protected against all applicable hazards.

Based on the location and design of the credited portions of the ESW system piping, as described in the PNPP UFSAR, and if implemented according to the licensee's SFP cooling strategy as described in the FIP, the NRC staff concludes that the credited flow paths should be available to support SFP cooling during an ELAP consistent with NEI 12-06, Section 3.2.1.3, Condition 6, and Section 3.2.1.6.

3.3.4.1.2 Primary and Alternate Connections

Section 3.2.2 of NEI 12-06 states that portable fluid connections for core and SFP cooling functions are expected to have a primary and an alternate connection or delivery point (e.g., the primary means to put water into the SFP may be to run a hose over the edge of the pool). It also states that, at a minimum, the primary connection point should be an installed connection suitable for both the on-site and off-site equipment, while the secondary connection point may require reconfiguration if it can be shown that adequate time and resources are available to support the reconfiguration. In addition, Section 3.2.2 states that both the primary and alternate connection points do not need to be available for all applicable hazards, but the location of the connection points should provide reasonable assurance that one connection will be available.

The licensee can provide SFP cooling from either the ESW "A" or "B" loop via a new 4-inch line. The 4-inch lines feed into a common 4-inch SFP fill header that is routed to the SFP. During the audit, the NRC staff reviewed Engineering Change Package Design Report 13-0515-000, Revision 4, to verify that the new piping installed for this feature is designed as seismically robust in accordance with NEI 12-06. The 4-inch lines and fill header are located in the Intermediate and Fuel Handling Buildings. According to PNPP UFSAR, Table 3.2-1, the Fuel Handling and Intermediate Buildings are Seismic Category I structures. The licensee's FIP states that action will be taken in Phase 2 to align SFP make-up.

As previously summarized in Section 3.3.2 of this evaluation, the licensee has the capability to provide remote pool make-up without access to the Fuel Handling Building. In addition, there is the capability for pool make-up to be achieved via either manually routed hoses, or hose-supplied portable spray nozzles. Thus, the NRC staff finds the licensee's SFP strategy incorporates the baseline capabilities consistent with NEI 12-06, Table C-3.

Based on the design and location of the connections the NRC staff concludes that at least one method should be available for SFP cooling in accordance with Section 3.2.2 of NEI 12-06.

3.3.4.1.3 Ventilation

The FIP states that, with the maximum postulated heat load in the SFP, a time estimate of over 11 hours is expected to pass before the pool would reach boiling conditions. The FIP continues by stating that this provides sufficient time in the mitigating strategies timeline to restore power and begin SFP cooling, such that a habitability evaluation for the area is not necessary. This is due to the fact that, based on the current strategies and analysis, there is no need for deployment of personnel into the SFP area.

Conservatively, the doors from the Fuel Handling Building to the outside on the east side of the plant will still be opened to provide a ventilation flow path. This action is controlled by procedure and the Timing and Deployment Timeline Table of the FIP shows that the action is expected to be completed within 2 hours of the ELAP-initiating event, prior to the overall time constraint of 4 hours.

Based on the expected timeline to boiling in the SFP, the strategy not relying on deployment of personnel to the SFP area during the time period when adverse conditions could be present, and the administrative controls to provide a ventilation flow path directly to the outside within 4 hours of the initiating event, the NRC staff concludes that the ventilation strategy for the SFP area should support the fulfillment of the SFP cooling strategies.

3.3.4.1.4 Plant Instrumentation

In its FIP, the licensee stated that the instrumentation for spent fuel pool level will align with 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 TGs. The NRC staff's review of the SFP level instrumentation, including the primary and backup 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 safety evaluation.

3.3.4.2 Thermal-Hydraulic Analyses

In NEI 12-06, Section 3.2.1.6 describes SFP initial conditions. Section 3.2.1.6, Condition 4, states that SFP heat load assumes the maximum design-basis heat load for the site. In accordance with NEI 12-06, the licensee performed a thermal-hydraulic analysis of the SFP using the maximum design basis heat load for the site.

Calculation X11-006, "FLEX Spent Fuel Pool Boil-Off Analysis," Revision 0, evaluates water lost from sloshing following a seismic event and the resultant time to boil and boil off rates. The licensee's evaluation determined that the SFP would start to boil at 10-12 hours for the normal SFP decay heat load and 5-6 hours for the maximum SFP decay heat load. The time required to boil off inventory to a water level of 10 feet above the fuel racks is approximately 122 hours for the normal SFP decay heat load and 47 hours for the maximum SFP decay heat load. This calculation also concluded that a make-up rate of 33 gpm would maintain SFP level stable for the normal decay heat load case and 85 gpm would maintain level for the maximum decay heat load case. The calculation also evaluated the amount of time for the SFP to start boiling for conditions where the reactor has been operating at 100 percent power for 100 days, consistent with the provisions of NEI 12-06, section 3.2.1.2.1. For this heat load, the SFP would start boiling at approximately 33 hours.

3.3.4.3 FLEX Pumps and Water Supplies

The licensee uses an electric powered FLEX pump, taking suction from the UHS and delivering water to the SFP vial the ESW system. The pump and corresponding licensee evaluation is discussed in Section 3.2.2.5 of this evaluation.

3.3.4.4 Electrical Analyses

The licensee's FIP defines strategies capable of mitigating a simultaneous loss of all ac power and loss of normal access to the ultimate heat sink resulting from a BDBEE by providing the capability to maintain or restore core cooling (the licensee's strategy for SFP cooling uses the same electrical strategy as for maintaining or restoring core cooling, inventory control, and containment). Furthermore, the electrical coping strategies are the same for all modes of operation.

The NRC staff performed a comprehensive analysis of the licensee's electrical strategies, which includes the spent fuel pool cooling strategy. The staff's review is discussed in detail in Section 3.2.2.6.

3.3.5 Conclusions

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

3.4 Containment Function Strategies

The industry guidance document, NEI 12-06, Table 3-1, 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. Perry is a BWR with a Mark III containment. The Mark III containment is not equipped with a hardened containment vent capable of performing the necessary pressure control and heat removal functions associated with an ELAP event; therefore, consistent with Table 3-1, the licensee has proposed an alternative containment heat removal mechanism to satisfy the requirements of Order EA-12-049. Specifically, PNPP will utilize FLEX equipment to repower a SPCU pump or an ADHR pump to circulate Suppression Pool water through the RHR HX. The cooling side of the heat exchanger will be supplied with water from the FLEX pumps in the ESPWH.

The licensee performed a containment evaluation, X11-001, "FLEX Event Coping Strategies and Time Analysis," Revision 0, which was based on the boundary conditions described in Section 2 of NEI 12-06. The calculation analyzed the alternative heat removal strategy and concludes that the containment parameters of pressure and temperature in the drywell remain below the respective UFSAR Table 6.2-2, Revision 15, design limits of 30 psig and 330 °F for at least 36 hours following an ELAP-inducing event. Both parameters are shown to be stable and/or trending down at the end of the 36-hour analyzed period. The 185 °F design limit for the wetwell (liquid) temperature is calculated to be exceeded by a peak value of approximately 40°F. A justification for exceeding this temperature limit is discussed in Section 3.4.4.1.1 of this safety evaluation.

Additionally, although core damage and subsequent hydrogen generation is not expected, NEI 12-06, Table 3-1, guides licensees with Mark III containments to repower the unit's hydrogen igniters by using a portable power supply as a defense-in-depth measure to maintain containment integrity. The FIP states that a train of hydrogen igniters will be repowered when the Division 1 or Division 2 vital buses are repowered and that this is expected to occur within 6 hours following an ELAP-inducing event.

3.4.1 Phase 1

During Phase 1, containment integrity is maintained by normal design features of the containment. Decay heat will be transmitted from the RPV to the Suppression Pool via RCIC steam exhaust and SRV operations. At the conclusion of Phase 1, which is stated in the FIP to occur approximately 6 hours after an ELAP-initiating event, the Suppression Pool temperature and containment pressure are expected to increase to ~12 psig and 225°F, respectively. This is within the aforementioned containment design pressure of 15 psig, but exceeds the Suppression Pool temperature limit of 185°F. A justification for exceeding this temperature limit is discussed in Section 3.4.4.1.1.

The FIP also states that essential instrumentation for monitoring containment parameters is powered from 125 Vdc busses ED-1-A, ED-1-B and ED-1-C. These busses are provided with individual 125 Vdc batteries; thus, the ability to monitor essential containment parameters during Phase 1 is maintained.

3.4.2 Phase 2

The FIP states that during Phase 2, FLEX TGs will be used to repower the Division 1 or Division 2 480 Vac buses and, in turn, the Suppression Pool Make-up (SPMU) dump valves, which are located inside the containment. The subsequent opening of these valves will allow the water in the upper pools (approximately 265,000 gallons) to be gravity-drained into the Suppression Pool. The added inventory from the upper pools will provide additional coping time and further prevents significant containment pressurization. As indicated in the Timing and Deployment Timeline Table of the FIP, this action is planned to occur no later than 6 hours after the ELAP-initiating event.

Also planned to commence no later than 6 hours after the ELAP-initiating event is the alignment of the Suppression Pool closed-loop cooling strategy. As mentioned in Section 3.4 above, the licensee will utilize FLEX equipment to repower a SPCU or ADHR pump to circulate Suppression Pool water through the RHR HX. The cooling side of the heat exchanger will be supplied with water from the FLEX pumps in the ESPWH. This method of containment cooling will continue until offsite equipment arrives from the NSRC and is aligned to initiate shutdown cooling via the repowered RHR and ESW systems.

The repowering of the Division 1 or Division 2 busses will also provide the hydrogen igniters with the necessary power to perform their function if required.

3.4.3 Phase 3

The arrival of additional generators from the NSRC will provide the necessary electrical capacity to place the RHR system in service in the shutdown cooling mode. The FIP also states that the additional electrical capacity will allow for additional flow to the ESW loops to be established by providing power to the "N+1" FLEX Lake Water pump.

3.4.4 Staff Evaluations

3.4.4.1 Availability of Structures, Systems, and Components

3.4.4.1.1 Plant SSCs

UFSAR Table 1.3-4 states that the PNPP utilizes a Mark III, steel containment (with pressure suppression) enclosed by a reinforced concrete reactor building. Table 3.2-1 of the UFSAR lists the Reactor Building Complex (which includes the drywell/interior structure, Suppression Pool, containment vessel, and Shield Building) as a Seismic Category I structure. UFSAR Sections 3.5 through 3.8 further define the design criteria for Seismic Category I structures and detail the effects of natural phenomena such as wind and tornadoes, floods, external missiles, and seismic events against which the structures are designed.

The SPMU System (which supplies a large volume of cooling water to the Suppression Pool from the upper containment pool in Phase 2) is listed in UFSAR Table 3.2-1 and Section 6.2.7.1 as a Safety Class 2, Seismic Category I system.

UFSAR Section 6.2.2.1.c, states the following regarding the containment heat removal system: "The system is designed to safety grade requirements including the capability to perform its function following a safe shutdown earthquake." Specifically, the RHR HXs, which are essential to the containment heat removal strategy, are shown in UFSAR Table 3.2-1 as being Seismic Category I components.

In accordance with NEI 12-06, the licensee evaluated the SPCU and ADHR pumps and associated piping in order to determine if the components would remain functional following a seismic event. The SPCU and ADHR pumps were evaluated under the ESEP and this evaluation process concluded that the pumps exhibited a high-confidence-low-probability-of-failure when subjected to the reevaluated seismic hazard for the site. Thus, the licensee concluded that the pumps would be available and able to perform their function following the seismic hazard. Section 5.5.3.7 of NORM-LP-7302, "FLEX Mechanical Design Report for the Perry Nuclear Power Plant", Revision 0, states that the ADHR system is a non-safety related system but was designed and installed with seismic loading requirements. It concludes that the ADHR system is robust for all FLEX initiating events because it is seismically qualified and located within a safety-related structure. For the seismic qualification of the SPCU discharge piping, the licensee performed a pipe stress calculation, 1G42G001A, "Piping Stress Analysis: Discharge Piping from Pump 1G42C0001 to Subsystem 1G41G007A", Revision 0. This calculation concluded that, with some support modifications, the SPCU piping met the appropriate stress criteria to be deemed robust in accordance with the definition of NEI 12-06.

UFSAR Section 6.2.8.1.1 states that the hydrogen igniters (which are part of the hydrogen control system) are designed as a safety grade system and are capable of operating for the duration of the hydrogen generation event. Furthermore, the igniter assemblies are classified and designed as electrical Class 1E and Seismic Category I.

As stated in Section 3.4 of this safety evaluation, the 185°F design limit for the Suppression Pool temperature is calculated to be exceeded by a peak value of approximately 40°F and remain over the limit for several hours during an ELAP event. The licensee performed an evaluation, summarized in its FIP, to confirm that the elevated Suppression Pool temperature does not compromise primary containment integrity. The evaluation focused on four specific, potential impact areas: the containment vessel, the piping systems which directly communicate with the Suppression Pool, containment penetrations, and the drywell wall.

To address the potential impact on the containment vessel, the licensee referenced their Individual Plant Examination Containment Capacity Analysis, which was prepared in response to Generic Letter 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities". The summary of this evaluation provided in the FIP discusses the impact of high temperatures on the reinforced concrete, reinforcement steel, steel plate (containment vessel, hatches, airlocks, etc.), and seal material. The summary further discusses the analysis that was performed for the containment vessel and how it relates to the prediction of containment performance during an ELAP scenario. Ultimately, the calculation determined that the containment was capable of withstanding an internal pressure of greater than 50 psig with a failure probability of only 5 percent. As stated above, the calculated containment pressure for an ELAP scenario is approximately 12 psig.

For the piping systems, which directly communicate with the Suppression Pool, the licensee performed a review to compare the thermal loads and stresses anticipated during an ELAP event to those loads and stresses anticipated for seismic events and hydrodynamic phenomena. Each of the segments of piping, which were evaluated by the licensee, were determined to be acceptable based on comparison to the previously analyzed seismic or hydrodynamic loads, or by new stress analysis required for demonstration of the adequacy of the alternate containment heat removal strategy.

The licensee's evaluation of the effect of the increased temperature on containment vessel penetrations was similar to the approach taken for piping systems. The FIP states that loads on the penetrations due to the piping were reviewed to confirm the relative magnitude of the thermal loads were similar when compared to the hydrodynamic loads. The review concluded that the ELAP scenario thermal loads were, in fact, bounded by the Operating Basis Earthquake (OBE) + SRV loads, pool swell loads, or chugging loads previously analyzed. Additionally, the FIP states that a review of drawings for the containment vessel and drywell wall showed no penetration seal material is located in these areas.

With respect to the drywell wall, the calculated conditions for the drywell during an ELAP scenario (see Section 3.4 above) are still within the design basis accident limits.

Regarding each of the above aspects of the potential consequences of the elevated Suppression Pool temperature that the licensee has addressed, the NRC staff finds that each of the topics has been adequately justified to demonstrate that there will not be significant adverse effects. Additionally, in Section 3.4.4.2 below, the staff has noted some conservative assumptions in the thermal-hydraulic analysis which should be considered in the overall evaluation of the containment response. Thus, the structural integrity of the containment should be maintained under the expected ELAP conditions. The staff further notes that the Grand Gulf Nuclear Station, which is also a BWR with a Mark III containment, was granted a license amendment to permanently increase the design temperature of the Suppression Pool to 210°F (ADAMS Accession No. ML121210003, non-public, proprietary information; a publically available version is available at ADAMS Accession No. ML121210020), only 15°F less than the value conservatively calculated by FENOC for the beyond-design-basis ELAP event.

Based on the above UFSAR qualifications, licensee calculations, and the implementation of the described plant modifications, the equipment essential to the containment heat removal and containment integrity protection strategies is robust, as defined by NEI 12-06, and would be available following an ELAP-inducing event.

3.4.4.1.2 Plant Instrumentation

NEI 12-06, Table 3-1, specifies that containment pressure, Suppression Pool temperature, and Suppression Pool level are key containment parameters which should be monitored by re-powering the appropriate instruments.

The FIP states that essential instrumentation for monitoring containment parameters is powered from 125 Vdc busses ED-1-A, ED-1-B and ED-1-C. These busses are provided with individual 125 Vdc batteries. The PNPP procedures provide guidance to cross-tie Unit 1 and Unit 2 batteries in each division within 30 minutes, and load shedding is also performed within 3 hours of the initiating event (see Timing and Deployment Timeline Table C.1-1). The mission time for the batteries is extended to greater than 24 hours per station calculations with the described operator actions. Therefore, the onsite FLEX TGs must be used to supply power to the battery chargers prior to 24 hours. As shown by FIP Table C.1-1, it is expected that the vital buses will be reenergized within 6 hours of an ELAP-initiating event.

Based on this information, the licensee should have the ability to appropriately monitor the key containment parameters, as delineated in NEI 12-06, Table 3-1.

3.4.4.2 Thermal-Hydraulic Analyses

The licensee performed calculation X11-001, "FLEX Event Coping Strategies and Timeline Analysis," Revision 0, to demonstrate the effectiveness of the proposed containment heat removal strategy. The calculation utilized the MAAP computer code, version 4.0.7, to model the heat-up and pressurization of the containment under ELAP conditions.

As stated in the FIP, Case 704 of this calculation models the containment response with the licensee's specific containment heat removal strategy being employed. It assumes that the reactor has been operating at 100 percent power for 100 days (as specified in NEI 12-06, Section 3.2.1.2) when the ELAP event occurs. Case 704 assumes that the SPMU pool volume is added to the Suppression Pool 6 hours after the ELAP-initiating event (consistent with Table C1-1 of the FIP). Furthermore, Case 704 considers the SPCLC strategy to commence 8 hours following an ELAP-inducing event (whereas Table C.1-1 of the FIP states the SPCLC alignment and SPCU/ADHR pump flow will be initiated by hour 7). The SPCLC conditions of Case 704 consider a process flow of 1500 gpm and a cooling flow of 1500 gpm on each respective side of the heat exchangers. The staff also noted that Case 704 (similar to Case 703) considers the suction source of the RCIC pump to be transferred to water from Lake Erie at approximately 7 hours after the initiating event.

During an ELAP event, the containment will begin to heat up and pressurize due to the discharge of the SRVs, leakage from the recirculation system, and the RCIC system exhaust steam as described in the core cooling strategy of Section 3.2.1 of this safety evaluation. Under these conditions and with the employment of the heat removal strategy, Case 704 concludes that the containment parameters of pressure and temperature in the drywell reach maximum values of 27.4 pounds per square inch absolute (psia) and approximately 200°F and then stabilize or decrease in the first 36 hours following an ELAP-inducing event. As stated in Section 3.4 of this safety evaluation, each of these values is below their respective UFSAR limit. The 185°F design limit for the wetwell (liquid) temperature is calculated to be exceeded by a peak value of approximately 40°F. A justification for exceeding this temperature limit is discussed in Section 3.4.4.1.1.

The staff noted that the calculation contains some conservative assumptions which are worth noting due to the exceedance of the Suppression Pool design temperature and the several possible suction sources for the core cooling and containment heat removal strategies (e.g. Suppression Pool, RHR HX outlet, Lake Erie). Namely, (1) Lake Erie is assumed to be at its design-basis upper temperature limit of 85°F, (2) the Suppression Pool is assumed to be at its

Technical Specification upper temperature limit of 95°F, (3) and the Suppression Pool level is assumed to be at 17'-6", which is below the Technical Specification lower level limit of 17'-9.5". Each of these assumptions are conservative and result in the calculation of higher temperatures than could be calculated if a "best estimate" calculation was performed.

3.4.4.3 FLEX Pumps and Water Supplies

The licensee uses an electric powered FLEX pump to provide water to the secondary side of the RHR HXs for Suppression Pool closed loop cooling. The discussion of this pump and the licensee's evaluation is discussed in Section 3.2.2.5 of this evaluation

3.4.4.4 Electrical Analyses

The licensee has performed a containment analysis based on the boundary conditions described in Section 2 of NEI 12-06. Based on the results of this analysis, the licensee evaluated whether actions would be required to ensure maintenance of containment integrity and instrumentation functions. The licensee's evaluation concluded that no actions are required during Phase 1.

The use of 4160 Vac TGs will allow electrical power to be provided to a large contingent of equipment offering versatility and flexibility during a beyond-design-basis event. Early in Phase 2, when 480 Vac power becomes available from a FLEX TG, the Upper Containment Pool will be dumped into the lower Suppression Pool by initiating SPMU. This requires manipulation of 480 Vac motor operated valves, and requires re-energizing one of the vital 480 Vac buses. During Phase 3, support to the safety functions includes using the NSRC generators to provide additional electric capacity to 4160 Vac vital buses.

3.4.5 Conclusions

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

3.5 Characterization of External Hazards

Sections 4 through 9 of NEI 12-06, 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 BDBEEs leading to an ELAP and loss of normal access to the ultimate heat sink.

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

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

References to external hazards within the licensee's mitigating strategies and this safety evaluation are consistent with the guidance in NEI-12-06 and the related interim staff guidance in JLD-ISG-2012-01 [Reference 7]. Coincident with the issuance of the order, on March 12, 2012 the NRC staff issued a Request for information Pursuant to 10 CFR Part 50, Section 50.54(f) [Reference 20] (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.

The NRC staff requested Commission guidance related to the relationship between the reevaluated flooding hazards provided in responses to the requests for information and the requirements for Order EA-12-049 and related rulemaking to address beyond-design-basis external events (see COMSECY-14-0037, Integration of Mitigating Strategies for Beyond-Design-Basis External Events and the Reevaluation of Flooding Hazards," dated November 21, 2014 [Reference 28]). The Commission provided guidance in a Staff Requirements Memorandum (SRM) to COMSECY-14-0037 [Reference 21]. The Commission approved the staff's recommendations that licensees 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. The licensee has submitted its flood hazard reevaluation report (FHRR) [Reference 22] in response to the 50.54(f) letter. However, based on results of its initial FHRR and interactions with the NRC staff [Reference 29], the licensee is preparing a revised FHRR that reflects certain plant and modeling changes, including major physical modifications to streams and watersheds at the site. The licensee plans to submit its reevaluated FHRR to the NRC staff by March 25, 2016. The licensee developed its OIP for mitigation strategies [References 10 and 11] by considering the guidance in NEI 12-06 and its then-current design-basis hazards. Therefore, this safety evaluation makes a determination based on the OIP and FIP, and only notes the possibility of future actions by the licensee when the licensee's FHRR identifies a flooding hazard which exceeds the current design-basis flooding hazard.

Per the 50.54(f) letter, licensees were also asked to provide a seismic hazard screening and evaluation report to reevaluate the seismic hazard at their site. The licensee completed a seismic hazard screening report (SHSR) [Reference 23] in March 2014 and the NRC staff has completed its review of the report [Reference 46]. The results are discussed in Section 3.5.1 below. The licensee developed its OIP for mitigation strategies [References 10 and 11] by considering the guidance in NEI 12-06 and its then-current design-basis hazards. Therefore, this safety evaluation makes a determination based on the OIP and FIP, and only notes the possibility of future actions by the licensee when the licensee's SHSR identifies a seismic hazard which exceeds the current design-basis seismic hazard.

The characterization of the specific external hazards for the plant site is discussed below. In addition, Sections 3.5.1 and 3.5.2 summarizes the licensee's activities to address the 50.54(f) seismic and flooding reevaluations.

3.5.1 Seismic

As previously discussed, the NRC issued a 50.54(f) letter that required facilities to reevaluate the site's seismic hazard (i.e., NTTF Recommendation 2.1). 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.

In its FIP, the licensee stated that the seismic hazard is applicable to the PNPP site. The maximum horizontal acceleration for the SSE is 0.15g. In its SHSR, the licensee stated that since the Ground Motion Response Spectrum (GMRS) exceeds the horizontal Safe Shutdown Earthquake (SSE) in the 1 to 10 Hz range, and also above 10 Hz range the site screens in to perform a risk evaluation, a Spent Fuel Pool (SFP) evaluation, and a High Frequency (HF) Confirmation.

The NRC staff reviewed the information provided by the licensee for the reevaluated seismic hazard for the PNPP site [Reference 46]. Based on its review, the NRC staff concluded that the licensee conducted the hazard reevaluation using present-day methodologies and regulatory guidance, it appropriately characterized the site given the information available, and met the intent of the guidance for determining the reevaluated seismic hazard. Based upon this review, the NRC staff confirmed the licensee's conclusion that the licensee's GMRS for the PNPP site exceeds the SSE in the 1 to 10 Hz range, and also above 10 Hz range. As such, a seismic risk evaluation, SFP evaluation, and HF confirmation are merited. Further, the NRC also concluded that the licensee's reevaluated seismic hazard was acceptable to address other actions associated with NTTF Recommendation 2.1: "Seismic.". The NRC staff revised this initial screening determination by letter dated October 27, 2015 [Reference 49]. Based on the NRC staff's comparison of the GMRS to the SSE and the review of additional hazard and risk information, the NRC concluded that a seismic probablisitic risk assessmsent was not necessary for PNPP. A HF and a SFP continue to be merited for PNPP in order to complete its response to the seismic portion of the March 12, 2012, 50.54(f) letter.

The licensee performed and submitted an ESEP report for PNPP [Reference 47] in response to the NRC's 50.54(f) letter to demonstrate seismic margin through a review of a subset of the plant equipment that can be relied upon to protect the reactor core following beyond-design-basis seismic events. This report was based on NRC-endorsed guidance prepared by EPRI [References 25, 26 and 27]. The NRC reviewed the ESEP [Reference 48] and concluded that, through the implementation of the ESEP guidance, the licensee identified and evaluated the seismic capacity of certain key installed mitigating strategies equipment that is used for core cooling and containment functions to cope with scenarios that involve a loss of all alternating current power and loss of access to the ultimate heat sink to withstand a seismic event that exceeds the re-evaluated seismic hazard for PNPP. The NRC also concluded that the ESEP assessment provides additional assurance which supports continued plant safety while the longer-term seismic evaluation is completed to support regulatory decision making.

As the licensee's seismic reevaluation activities are completed, the licensee will enter appropriate issues into the corrective action program. The licensee has appropriately screened in this external hazard and identified the hazard levels for reasonable protection of the FLEX equipment.

3.5.2 Flooding

In its FIP, the licensee stated that flooding was not initially considered a site-specific (applicable) hazard as the site was originally considered a dry site. Assuming the worst case (i.e., complete blockage of the site storm drainage system and using peak discharge from the most intense hour of the Probable Maximum Precipitation (PMP)), the resulting increase in surface elevation of water would not exceed an elevation of 620 feet 5 inches. This will have no adverse effect upon safety class equipment because the floors at plant grade are set at Elevation 620 feet 6 inches. However, during subsequent analysis, the licensee identified a condition on the west side of the plant where the site elevation is approximately 2.5 inches below external benchmarks. This condition was entered into the site corrective action program and compensatory measures have been established to eliminate the potential for water intrusion into susceptible door penetrations during a Probable Maximum Flooding (PMF) event. In the long-term, modifications to the adjacent unnamed major and minor streams surrounding the site are planned to permanently address the external flooding hazards for PNPP.

The licensee has submitted its FHRR [Reference 22]. The flood reevaluation considered eight potential flood causing mechanisms and a combined effect flood required by the 50.54(f) letter. The reevaluation showed that the current design-basis flood levels are exceeded for the following potential flood mechanisms: local intense precipitation, flooding in rivers and streams, Lake Erie storm surge, and combined effect flooding. In its FHRR, the licensee described an interim action plan to perform modifications to certain major and minor streams to demonstrate maximum water surface elevations will not result in flooding of plant buildings important to nuclear safety. By letter dated March 24, 2016 [Reference 57], the licensee submited a revised FHRR that reflects current site conditions as a result of the topographical modifications. The NRC staff is currently reviewing this revised FHRR.

With regard to the potential for internal flooding from large sources that are not seismically robust and do not require ac power, the licensee indicated that one potential flooding source is the Circulating Water System and that failure of this system internal to plant structures will result in flooding of the turbine power complex (TPC), Turbine Building (TB), and heater bay (HB). This postulated flooding scenario is described in the UFSAR Sections 2.4.13.5 and 10.4.5.3.2. During the onsite audit, the licensee stated that there are no FLEX related operator actions within these plant locations. Plant design provides for flooding of the TPC, TB, and HB during a circulating water system failure without flooding of the Auxiliary Building or other safety related structures. In addition, the licensee stated that no equipment required for FLEX strategies is located in these plant areas. Regarding non-robust tanks internal to building structures, the licensee described another potential source of flooding is from the Radwaste Storage Tanks, which are located internal to the plant in the lowest elevation of the Radwaste Building. The licensee stated that the Radwaste building is not required for equipment support or personnel access as part of the site FLEX strategy. During the audit, the NRC staff walked down the areas associated with FLEX implementation and did not identify any concerns with the licensee's assessment of non-seismically robust internal flooding sources.

During the audit, the NRC staff reviewed the passive system for mitigation of ground water intrusion. Initially, it was not clear to the staff how the passive portion of this system will maintain ground water elevation below the 590 foot elevation with no pumping power when the flood level around the plant may be at the 620 foot elevation. In the FIP, the licensee described that the gravity discharge system is designed to provide a redundant periphery discharge, which incorporates a gravity outfall, having no active components, that can handle a 15,000 gpm flow entering the under drain system on either side of the plant. Further, the UFSAR [Reference 51], Section 3.4.1.1, describes how the safety class structures located below finished grade are protected on their outside surfaces by a continuous waterproofing membrane, with water stops being provided at construction joints.

According to the licensee, there are no potential site impacts from the failure of non-seismically constructed dams. The NRC staff reviewed the UFSAR, Section 2.4.4, which states that dam failure is not a design condition, to confirm this assessment.

As the licensee's flooding reevaluation activities are completed, the licensee will enter appropriate issues into the corrective action program. The NRC staff review finds that the licensee has appropriately screened in this external hazard and identified the hazard levels for reasonable protection of the FLEX equipment.

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. If the resulting frequency of recurrence of hurricanes with wind speeds in excess of 130 miles per hour (mph) exceeds 10^{-6} per year, the site should address hazards due to extreme high winds associated with hurricanes.

The screening for high wind hazard associated with tornadoes should be accomplished by comparing the site location to NEI 12-06, Figure 7-2. If the recommended tornado design wind speed for a 10^{-6}/year probability exceeds 130 mph, the site should address hazards due to extreme high winds associated with tornadoes.

In its FIP, regarding the determination of applicable extreme external hazards, the licensee described that for PNPP, the calculated Probable Maximum Hurricane (PMH) wind speed is 102 mph, below the 130 mph characteristic set forth in the NEI guide and as tropical cyclones including hurricanes lose strength rapidly as they move inland, the greatest concern then becomes the potential damage from flooding due to excessive rainfall. Additionally, during Hurricane Agnes in 1972, the maximum hourly wind speeds (15-minute average) recorded at the PNPP site were 28.0 mph at the 35-foot level and 39.5 mph at the 200-foot level.

With regard to high winds from tornados, in its FIP, the licensee stated that PNPP is located at 41.8008° N, 81.1433° W which falls under Region 1 of NEI 12-06 Figure 7-2, therefore, high wind hazards from tornados must be considered. The PNPP FIP characterizes the tornado wind speed design for the PNPP consistent with the description contained in the UFSAR Table 2.3-5.

Therefore, the licensee has concluded that high-wind hazards are applicable to the plant site. The NRC staff review finds that the licensee has appropriately screened in this external hazard and identified the hazard levels for reasonable protection of the FLEX equipment.

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 their 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 of NEI 12-06 should address the impact of ice storms.

In its FIP, regarding the determination of applicable extreme external hazards, the licensee states that PNPP is above the 35th parallel and therefore must provide the capability to address extreme snowfall with snow removal equipment. The licensee also stated that, according to Figure 8-1 of NEI 12-06, PNPP is located in the area where a 3-day snowfall of up to 36 inches should be anticipated. The licensee further described that PNPP is a Level 3 region, as defined by NEI 12-06, Figure 8-2 and therefore the PNPP FLEX strategies must consider the impact of ice storms.

In its FIP, the licensee described that the UFSAR discusses the potential for ice blockage of the intake structure. During extreme low temperatures, it is possible that Lake Erie will develop frazil ice on its surface; however, the intake structures to the UHS are approximately 2,600 feet offshore and well below the surface of the water. Therefore, the possibility of floating ice sheets being pulled down and blocking the ports is very remote because of the very low intake velocities. The intake structures are protected by reinforced concrete ice protection caissons around them, which will act as a barrier to any floating ice island, which could block the intake ports. For the very unlikely case where complete blockage of the intake structures would occur, water can be drawn from the discharge tunnel. Therefore, flow blockage from ice is not considered a hazard for the site.

In summary, based on the available local data and Figures 8-1 and 8-2 of NEI 12-06, the plant site can experience significant amounts of snow, ice, and extreme cold temperatures; therefore, the licensee concludes that this hazard is screened in. The NRC staff review finds that the licensee has appropriately screened in this external hazard and identified the hazard levels for reasonable protection of the FLEX equipment..

3.5.5 Extreme Heat

In the section of the FIP regarding the determination of applicable extreme external hazards, the licensee described that, as per NEI 12-06 Section 9.2, all sites are required to consider the impact of extreme high temperatures. Normal temperatures representative of the region are taken at Cleveland-Hopkins Airport located in Ohio, approximately 50 miles west of the PNPP site. Monthly and annual values of daily mean temperature and average and extreme daily maximum and minimum temperatures are shown in PNPP UFSAR, Table 2.3-8, based on data records for Erie, Cleveland, and the PNPP. From this data, the monthly averages indicate that July and August are the hottest months and February the coldest month. The annual average and extreme mean temperatures in the site area is 49°F and 55°F respectively, while the hottest average maximum temperature is 90°F. Additionally, the maximum-recorded temperature in the area around the PNPP site between 1942 and 1978 was 103°F (UFSAR, Table 2.3-4).

In summary, based on the available local data and the guidance in Section 9 of NEI 12-06, the licensee concludes that the plant site does experience extreme high temperatures. The NRC staff review finds that the licensee has appropriately screened in this external hazard and identified the hazard levels for reasonable protection of the FLEX equipment.

3.5.6 Conclusions

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

3.6 Planned Protection of FLEX Equipment

3.6.1 Protection from External Hazards

In its FIP, the licensee described that FLEX equipment will be stored in existing buildings that are capable of ensuring that equipment is being stored in a location capable of withstanding a SSE, the site design-basis extreme wind conditions, and the other postulated external events as described in NEI 12-06. These locations are: (1) in the common unit Diesel Generator building (FLEX Equipment Bay 1 part of an existing safety related Seismic Category I structure), (2) the Auxiliary Building of the unfinished Unit 2 (FLEX Equipment Bay 2, an existing structure originally built to safety related Seismic Category I standards), and (3) the Emergency Service Water Pump House (ESWPH, an existing safety related Seismic Category I structure) for the FLEX Lake Water pumps.

According to the FIP, as revised, Tables B-2 and B-3, portable equipment stored in FLEX Equipment Bay 1 (common unit EDG building) includes: two of three 4160 Vac generators and cables, two of seven 6000W portable generators, fire hose, diesel fuel oil transfer hose, one of two portable light towers, three of five portable electric fans, two 250 gpm portable pumps, and one of two debris removal pickup trucks. Portable equipment stored in FLEX Equipment Bay 2 (the unfinished Unit 2 Auxiliary Building) includes: a 2 cfm air compressor, two portable electric fans, fire hose, air hose, the second of two portable light towers, third of three 4160 volt generators and cables, five of seven 6000W portable generators, one Bobcat loader, the second of two debris removal pickup trucks, and two Transcube™ Fuel Oil tanks. Portable equipment stored in the ESWPH consists of two FLEX Lake water pumps and the associated discharge hoses.

3.6.1.1 Seismic

In its FIP, the licensee described that FLEX equipment will be stored in existing safety related Category I buildings. In the OIP, the licensee described that FLEX equipment will be secured as appropriate during an SSE and will be protected from seismic interactions from other components. During the audit process, the NRC staff reviewed PNPP document NOP-LP-7304, "FLEX Programmatic Controls Report for the Perry Nuclear Power Plant (PNPP)," Revision 0, Appendix A, Table 4.2.1-1 which requires that FLEX equipment be secured as appropriate for a potential SSE and will be protected from seismic interactions from other components.

3.6.1.2 Flooding

Section 3.5.2 of this safety evaluation describes the PNPP flooding evaluation. Storage of equipment will be in existing robust structures with floors/entrances at elevation 620'-6", slightly above the postulated maximum flood height. Specifically, FLEX Equipment Bays 1 and 2 have floor elevations above the flood height. The ESWPH where the FLEX Lake Water pumps are stored has a normal access point at elevation 620 feet 6 inches, above the maximum site flood level of 620 feet 5 inches. The ESWPH has a floor elevation of 586 feet 6 inches. Maximum suction bay water height based upon maximum lake levels and surge heights is 580 feet based upon the location of the intake structures approximately 1/2 mile off shore. The ESWPH is designed to preclude ground water in-leakage with sealed penetrations. Any incidental in-leakage from ground water or system failures would be drained below the 580 feet 6 inches floor level by grating openings above the suction bay of the pump house and back to the lake via the intake structure.

3.6.1.3 High Winds

As described in section 3.6.1 of this safety evaluation, all FLEX equipment is stored in existing safety related buildings or in a building capable of withstanding the site design-basis high wind conditions (including tornado missiles). According to the licnesee, this meets the protection guidance for external events identified in NEI 12-06, such as storms with high winds, and tornadoes.

3.6.1.4 Snow, Ice, Extreme Cold and Extreme Heat

In its FIP, the licensee described that all FLEX equipment is stored in locations that provide protection from the extreme cold hazards at the site (including ice storms). According to the licensee, the storage locations, the close proximity of the storage locations to the operational locations, and the use of debris removal provisions ensures that the FLEX equipment is available, deployable, and functional.

The licensee's FIP describes how FLEX equipment is protected from extreme heat. This includes provisions that storage locations for FLEX equipment include portable fans that can be powered from small portable generators to provide adequate ventilation to FLEX equipment in storage or deployed for use. Procedure guidance exists to provide monitoring of storage areas to ensure continued functionality of the FLEX equipment. According to the licensee, FLEX Equipment Bay 1, which has no forced ventilation, will not result in any adverse environmental conditions based on weather conditions experienced during the plant life [Reference 58]. Storage of FLEX equipment in FLEX Equipment Bay 2, which likewise has no forced ventilation, does not have any adverse environmental conditions expected based on weather conditions experienced during the plant life in this area. Based on temperatures experienced in this area during the plant life, it has been less than 105°F. FLEX equipment stored in this area has been procured to meet the design and licensing basis high temperature of 105°F. As a result, the licensee concludes that FLEX equipment will not be impacted by adversely high temperature conditions in storage.

3.6.2 Reliability of FLEX Equipment

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

The NRC staff reviewed the number of portable FLEX pumps, FLEX TGs, and support equipment identified in the FIP. The staff finds that, if implemented appropriately, the licensee's FLEX strategies include a sufficient number of portable FLEX pumps, FLEX TGs, and equipment for RPV make-up and core cooling, SFP make-up and maintaining containment consistent with the "N+1" recommendation in Section 3.2.2 of NEI 12-06.

3.6.3 Conclusions

Based on the licensee's plan to store all of their onsite portable FLEX equipment in fully protected structures, the NRC staff review finds that the licensee has provided storage locations that are appropriately protected from the applicable external hazards for the site in accordance with the provisions of NEI 12-06. Further, the NRC staff finds that the licensee has stored sufficient equipment at these designated locations to accomplish the elements of their overall strategy that depend on this equipment (primarily Phase 2 operations). Therefore, 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, as endorsed, by JLD-ISG-2012-01 and should adequately address the requirements of the order.

3.7 Planned Deployment of FLEX Equipment

In the FIP, deployment of FLEX equipment is described for each FLEX function and all operating modes. The deployment strategies are unchanged for the different operating modes. The deployment strategies from the FLEX storage locations to each staging area are identified.

Equipment transportation, fuel transportation, debris removal, security barriers, and lighting concerns are discussed as they apply to each FLEX strategy.

In its FIP, the licensee described deployment paths, which refer to the route from a storage location to the staging location for various equipment, and routing paths, which refer to the route from a staging location to the point of connection to existing plant equipment for hoses and cables. Deployment paths and routing paths are shown in Appendices to the FIP for all strategies.

3.7.1 Means of Deployment

In its FIP, the licensee lists in Appendix: B-2, On-Site Phase 2 Equipment Requirements, two pickup trucks for "equipment deployment" and debris/snow removal. Though not specifically credited in the strategy, the licensee has identified in their FIP one skid loader "Bobcat" stored in Equipment Bay 2 for defense-in-depth regarding debris removal.

3.7.2 Deployment Strategies

On pages 21 and 46 of its OIP [Reference 10], the licensee states that site evaluations have determined that no soil liquefaction will occur during a seismic event. During the audit process the licensee noted that UFSAR Section 2.5.4.1.5 indicates that the geology supporting the plant foundations is not susceptible to liquefaction. UFSAR Section 2.5.1 indicates that the geological evaluation applies to the entire site, which would include the local staging area. The NRC staff reviewed these sections of the PNPP UFSAR and finds that these UFSAR conclusions are applicable to the deployment plan and thus liquefaction should not inhibit the necessary equipment deployment after an earthquake. PNPP document NOP-LP-7304, "FLEX Programmatic Controls Report for the Perry Nuclear Power Plant (PNPP)," Revision 0, describes that flooding of deployment areas is not a concern as all areas are above grade level (El. 620 feet 5 inches) or within credited structures.

The FLEX Lake Water pumps will be pre-staged in the ESWPH. The primary power for these electric driven pumps will be provided by a FLEX TG feeding the Unit 2 EH-21 bus via a distribution center, located in FLEX Equipment Bay 1. In its FIP, the licensee described that during a FLEX event, the two "N" set of TGs will be deployed to the area west of the Diesel Generator Building and east of the Underground Fuel oil storage tanks. A set of single phase cables will be run from each FLEX TG to the distribution center within FLEX Equipment Bay 1 through either the outside man door or the roll up door. A fuel line will be run from the sample valve on a Day Tank (Division 1, Division 2, or Division 3 can be used) to the first FLEX TG; a second fuel line will be run from a different Day Tank to the second FLEX TG.

In its FIP, the licensee described that in the event that a single FLEX TG fails, the spare FLEX TG will be used to replace the failed FLEX TG. Two diverse methods to use the spare FLEX TG are provided. If a travel path from FLEX Equipment Bay 2 to FLEX Equipment Bay 1 is, or can be, established within 2 hours, the spare TG is moved to the primary FLEX TG deployment area west of the Diesel Building and east of the in-ground Fuel Oil Storage Tanks. It is then connected to the distribution center in the same manner as the failed TG. If no travel path from FLEX Equipment Bay 2 to FLEX Equipment Bay 1 can be established within 2 hours, the spare

TG is moved to the ESWPH where a set of single conductor cables is run from the spare FLEX TG to the ESWPH termination enclosure (in the ESWPH) to supply the FLEX Lake Water pump. If this is the only ac power source, Bus EH21 will be back fed from the ESWPH termination enclosure through breaker EH 2106 to provided limited electrical power. A portable fuel oil tank with approximately 1200 gallon capacity called a Transcube™ fuel oil tank will be used to supply fuel for the spare FLEX TG.

3.7.3 Connection Points

3.7.3.1 Mechanical Connection Points

For core cooling while RCIC is still available in Phases 1 and 2, the principal robust water supply is the Suppression Pool. In its FIP, the licensee describes that in Phase 2 when SPCLC is established the RCIC suction is shifted to the outlet of the RHR HX to use the Suppression Pool water that is being pumped through the RHR system by the SPCU/ADHR pump. The preferred robust RCIC alternate water source is the new 5-inch Storz connection off the RHR to FPCC return header. Once SPCLC is in service, the RHR system is connected to the RHR to FPCC return header. This aligns water from the RHR HX outlet to the FPCC Supplemental Cooling return header. From the new 5-inch Storz connection, a hose is connected to a dry stand pipe connection on Auxiliary Building Elevation 599 feet. A second hose is connected to the dry stand pipe 5-inch Storz connection on Auxiliary Building Elevation 568 feet and routed to the RCIC suction 5-inch Storz connection on Auxiliary Building Elevation 574'. All of these connections are within the Auxiliary Building, a Seismic Category I structure, and are protected from all postulated external hazards.

If SPCLC cannot be established, heatup of the Suppression Pool challenges RCIC system operation and in the FIP, the licensee described that the alternate robust source of cooling water is Lake Erie (UHS). FLEX Lake Water pumps, which draw on Lake Erie, are pre-staged in the ESWPH. Once a pump is lowered into the ESWPH forebay, 10 foot long discharge hoses are connected between the pumps three, 5-inch Storz connections on the pump manifold and the ESW "A" loop's three, 5-inch Storz connections, the (two per connection) 6 inch manual isolation valves are then opened (6 total). Once electrical power is available, the FLEX Lake Water pump is started. All these connections are within the ESWPH, which is a Seismic Category I structure, and is protected from all applicable hazards. For a secondary connection, the ESW "B" pump discharge piping has been modified by adding three 5-inch Storz connection points to allow either of the two FLEX Lake Water Pumps to be connected to the ESW "B" Loop. These connections are located between the ESW "B" Pump discharge check valve and the discharge strainer, which are similarly located within the ESWPH and thus, are protected from all external hazards.

The licensee further described that if RCIC operation is not available, the Emergency Operating Procedures (EOPs) will direct lowering RPV pressure to allow low-pressure injection systems to feed the RPV. The HPCS and LPCS systems contain flush connections that connect into the system between the pump and injection valve. The HPCS system has a previously installed 5-inch Storz connection used for "Fast Firewater" and Alternate Boron Injection. The LPCS has a flush line similar to the HPCS connection, and this line was modified to accept a standard fire hose for low-pressure vessel injection. Either of these connection points can be aligned to alternate sources for RPV Injection. If RCIC is or becomes unavailable, a hose connection on the LPCS pump discharge piping is provided for vessel injection to allow for the use of an alternate water source on Auxiliary Building, Elevation 620' East Side. This connection allows the LPCS system piping to be connected to the ESW supply piping connection on Auxiliary Building, Elevation 599' via one of two dry standpipes that run from Auxiliary Building, Elevation 620' to the Auxiliary Building, Elevation 574' (568') with connection points on each floor. All of these connections are within the Auxiliary Building and are protected from all external hazards.

With regard to SFP cooling, the licensee describes in its FIP that no coping strategy is required during Phase 1. Starting in Phase 2, NEI 12-06 guidance specifies three methods of filling the SFP: Fill from a location external to the pool area, fill using hoses and fill using spray. The fill from the external location and hoses must be capable of making up for losses due to boil off and the spray flow must be capable of 250 gpm. To meet these capabilities, starting in Phase 2, an emergency make-up system (providing lake water from the FLEX pumps via the ESW system) is installed. All connections are within Seismic Category I Structures and are protected from all postulated external hazards.

In its FIP, the licensee describes that access to cooling water from Lake Erie is not hindered by icing or frazil ice. The UFSAR discusses the potential for ice blockage of the intake structure. In extreme low temperatures, it is possible that the cooling lake will develop frazil ice on its surface; however, the intake structures to the UHS are approximately 2,600 feet offshore and well below the surface of the water. Therefore, the possibility of floating ice sheets being pulled down and blocking the ports is very remote because of the very low intake velocities. The intake structures are protected by reinforced concrete ice protection caissons around them, which will act as a barrier to any floating ice island, which could block the intake ports. For the very unlikely case where complete blockage of the intake structures would occur, water can be drawn from the discharge tunnel. Therefore, flow blockage from ice is not considered a hazard for the site.

3.7.3.2 Electrical Connection Points

In its FIP, the licensee described that Phase 2 strategies use installed and portable on-site equipment that will be deployed to plant locations to provide for continued RPV make-up and SFP cooling, as well as power to the FLEX pumps and vital 480 Vac buses. Portable FLEX TGs will provide power to all necessary loads. The electrical equipment will be relied upon throughout Phase 2 and be supplemented by NSRC equipment in Phase 3. The site FLEX TGs and the NSRC TGs are identical equipment and the FLEX modifications supports up to four generators being used in parallel without the need to de-energize vital loads during connection of additional generators. These specific connections are described in Section 3.7.2 of this safety evaluation. As described in that section, all electrical connection points are located in either the Diesel Generator building or the ESWPH; thus all connections are within Seismic Category I structures and are protected from all postulated external hazards.

3.7.4 Accessibility and Lighting

In its FIP description of Phase 1 actions, the licensee described that Control Room emergency lighting is powered by the plant batteries and adequate portable lighting is provided to support activities outside of the Control Room. With regard to equipment deployment, the licensee described that if the activity occurs at night, lighting is required to support the transport. Lighting used for this purpose is expected to be portable and not seismically robust. In the FIP Appendices, Table B-2, On Site Phase 2 Equipment Requirements lists 2 portable light towers, available for this purpose. During Phase 2, once the FLEX Generators are supplying power, Control Room lighting will be restored by providing 110 Vac power to the Control Room.

During the audit process, the licensee indicated that areas requiring access for instrumentation monitoring or equipment operation may require portable lighting as necessary to perform essential functions. Flashlights are standard equipment for plant operators. Operators are required to carry flashlights in accordance with the operator tours section of NORM-OP-1002, "Conduct of Operations," Revision 3. Normal Appendix R Emergency lighting is also available to provide lighting in critical areas during the first part of the event. As part of a lighting assessment for FLEX implementation, the licensee added permanently installed battery backed lighting to the ESWPH to facilitate mitigating strategies activities at that location under Engineering Change Package (ECP) 13-0523, "FLEX Modifications for Emergency Lighting," Revision 6.

3.7.5 Access to Protected and Vital Areas

In the FIP, Section 13.0, the licensee states that, "Strategies for protection of the stored portable emergency equipment and for assuring access for deployment of that equipment for these external events have been implemented." During the audit process, the licensee indicated that security personnel are available to provide support in the opening/unlocking of doors if needed and that FSG procedures will list the doors needed for access. As a backup, the shift manager has a key to vital areas under his control.

3.7.6 Fueling of FLEX Equipment

In its FIP, the licensee included a description of the equipment that may require diesel fuel during Phases 2 and 3, including:

- FLEX 4160 Vac TGs at the Diesel Generator Building
- FLEX 4160 Vac TG at the ESWPH
- Portable FLEX instrument air compressor for ADS backup

The FLEX TGs do not have an onboard fuel tank. The TGs are equipped with fuel pumps that can be used to take suction on an external supply. For the two "N" set TGs that will be used at the Diesel Generator Building, a hose will be connected to the DG Fuel Oil (FO) transfer pump suction line drain valve on one of the three diesel generator day tanks. Any of the day tanks can be used and the selection will be event specific based upon availability. Each day tank has approximately 3 hours of fuel supply before the auto transfer of fuel oil from the storage tank to the day tank is disabled due to low tank level. From the time that the FLEX TG is started until the critical 480 Vac divisional busses are energized, is estimated to be less than 1 hour. This is sufficient time to restore power to the associated division critical 480 Vac to allow the fuel oil transfer pumps to be restored to normal operation and automatically supply make-up needs of the day tank.

Establishing the fuel oil supply involves connecting a hose from the DG FO pump suction valve and routing the hose to the FLEX TG and connecting the hose to the TG fuel oil connection. As another option, any of the three in-ground fuel oil storage tanks can be used by running a hose to the tanks dewatering or dip stick connections and pumping fuel directly to the TG.

For the "N+1" TG that will be used if an "N" TG is unavailable, the "N+1" TG will be moved from the Unit 2 Auxiliary Building and staged outside the Diesel Building to replace the failed "N" generator. If access to the Diesel Building is precluded due to debris, the "N+1" TG will be moved from the Unit 2 Auxiliary Building and staged outside the ESWPH. As part of this deployment, a Transcube™ fuel oil tank will be staged by the TG to serve as the fuel oil tank for the TG. This will provide 12 hours of operation before refueling is required. Three pumps are provided to assist in this transfer of fuel oil, a 110 Vac pump, a 12 Vdc pump and a hand pump. Portable 110 Vac generators are available to be used to power the 110 Vac pump.

The FLEX air compressor (88 scfm capacity) is assumed to be deployed at T=12 hours and have 5 gallons of fuel on-board and a consumption rate of 1.5 gph. Hence, refueling must occur between T=15 and T=16 hours. This compressor will be refueled using a 28 gallon capacity fuel caddy, however, this equipment is not critical and is a back up to the 7-day air supply in the ADS storage tanks.

Total refueling demand from on-site resources is about 4000 gallons (assuming 18 hours of FLEX TG operation at full load). The 184,220 gallons (technical spececification minimum values) in the three fuel oil storage tanks could then support well over 24 hours of Phase 2 operations.

During the audit, the licensee described that in addition the normal fuel oil supply vendor has a long term contract and has provided fuel oil reliably for several years. Actions taken by the fuel oil vendor in the past have indicated their understanding and support of maintaining adequate fuel oil supply at the PNPP during emergency conditions. This vendor has access to over two million gallons of diesel fuel oil in the local area as well as an emergency supply of over 250,000 gallons. In addition, oil from refineries in Toledo, Ohio and Canton, Ohio are also available to the fuel vendor, essentially ensuring an indefinite supply.

During large scale events that activate the licensee's emergency facilities, state and county support will be provided for ensuring that the licensee has the necessary resources to respond to the event.

3.7.7 Conclusions

Based on this evaluation, the NRC staff concludes that the licensee has developed guidance that, if implemented appropriately, should allow deploying the FLEX equipment following a

BDBEE consistent with NEI 12-06, as endorsed, by JLD-ISG-2012-01 and should adequately address the requirements of the order.

3.8 Considerations in Using Offsite Resources

3.8.1 PNPP SAFER Plan

In its FIP, the licensee described that the industry has established two NSRCs to support utilities during BDBEE. Each NSRC holds five sets of equipment, four of which can be fully deployed when requested, the fifth set may have equipment in a maintenance cycle. Equipment is moved from an NSRC to the near site staging area, established by the Strategic Alliance for FLEX Emergency Response (SAFER) team and the utility. Communications are established between the affected nuclear site and the SAFER team and required equipment moved to the site as needed. First arriving equipment, as established during development of the SAFER Response plan, is to be delivered to the site within 24 hours from the initial request. The licensee has signed a contract with SAFER to meet the requirements of NEI 12-06.

By letter dated September 26, 2014 [Reference 24], the staff issued its staff 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.

3.8.2 Staging Areas

In general, up to four staging areas for NSRC supplied Phase 3 equipment are identified in the SAFER Plans for each reactor site. These are a Primary (Area "C") and an Alternate (Area "D", if needed), which are offsite areas (within 25 miles of the plant) for receipt of ground transported or airlifted equipment from the SAFER centers in Phoenix, Arizona, or Memphis, Tennessee. From Staging Areas "C" and/or "D", a near or on-site Staging Area "B" is established for interim staging of equipment prior to it being transported to the final location for implementation in Phase 3 at Staging Area "A". For PNPP, Alternate Staging Area "D" is not used. Staging Area "C" is the Northeast Ohio Regional Airport. Staging Area "B" is an onsite parking lot. Staging Area "A" is the area west of the EDG Building and east of the underground fuel oil storage tanks.

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

3.8.3 Conclusions

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

3.9 Habitability and Operations

3.9.1 Equipment Operating Conditions

3.9.1.1 Loss of Ventilation and Cooling

Following a BDBEE and subsequent ELAP event, plant HVAC in occupied areas and areas containing permanent plant and FLEX mitigation strategy equipment will be lost. Per NEI 12-06, FLEX mitigation strategies must be capable of execution under the adverse conditions (unavailability of normal plant lighting, ventilation, etc.) expected following a BDBEE resulting in an ELAP and a loss of normal access to the ultimate heat sink. The primary concern with regard to ventilation is the heat buildup, which occurs with the loss of forced ventilation in areas that continue to have heat loads.

The areas identified for all phases of execution of the FLEX mitigation strategy activities are the Reactor Core Injection Cooling (RCIC) Pump Room, Control Room, Containment, Switchgear Room, Battery Charger Room, and Battery Room. The licensee evaluated these areas to determine the temperature profiles following an ELAP and a loss of normal access to the ultimate heat sink event.

The FIP states that procedural guidance is provided in FLEX Support Guideline (FSG) 90.3, "Alternate Room Ventilation" which will open the RCIC Room door and install portable fans to address extended use of RCIC in supplying supplemental ventilation for the RCIC Room. Direction for these actions is provided in ONI-R10-2, "Station Blackout (SBO)" and in FSG 10.1, "RCIC FLEX Operation."

The NRC staff reviewed Calculation X11-003, "FLEX Transient Thermal Analysis of Auxiliary Building Following an ELAP Scenario," Revision 0, which indicated that the peak high temperature in the RCIC Pump Room will be maintained below 150°F for Phases 1 and 2, while crediting operator actions (opening doors, deploying fans etc.). Calculation X11-002, "RCIC System FLEX Vulnerability Review," Revision 0, determined that the temperature qualification of the RCIC governor components located in the RCIC Pump room is 150°F. Since the room temperature remains below the critical component qualification temperature, the NRC staff finds that it is reasonable to assume that the RCIC system will function during an ELAP event.

The NRC staff reviewed Calculation X11-010, "Transient Thermal Analysis of Control Room following an ELAP Scenario," Revision 0, which modelled the Control Room temperature transient when all control room cooling is lost. This calculation determined that control room temperatures reach a maximum of approximate 95°F wet bulb temperature and 103°F dry bulb temperature during the warmest part of the day when outside air is provided through the control room ventilation. Activation of fans will reduce the temperature rise during the initial period of the transient. However, establishing Control Room ventilation will be needed to prevent higher temperatures in accordance with the licensee's FSGs in Phase 2 and Phase 3.

Based on Control Room 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," Revision 1, for electronic equipment to be able to survive indefinitely), the NRC staff finds that it is reasonable to assume that the equipment in the Control Room will not be adversely impacted by the loss of ventilation as a result of an ELAP event.

For the Battery Charger and Switchgear Rooms, the licensee provided an analysis for the control building complex with a complete loss of ventilation representative of ELAP conditions, ECA-75, "GOTHIC Analysis of the Perry Control Complex for Loss of Ventilation to Zone CB-2," Revision 0. This evaluation showed that the Switchgear Room and Battery Room temperatures would conservatively reach 82 and 92°F 12 hours after the initiating event. During the audit, the licensee indicated that due to their proximity the Battery Charger room would be expected to be representative of temperatures in the Battery Room under ELAP conditions. Since the licensee's strategy will restore ventilation to all of these areas well before 12 hours and the temperature is well below the guidelines of NUMARC 87-00 for electronic equipment, the NRC staff finds that it is reasonable to assume that the electrical components in these rooms necessary to implement the strategy will perform as intended.

In its FIP, the licensee stated that during normal operation, the temperature in the battery rooms can vary from 72°F to 80°F. The highest temperature of battery electrolyte was recorded as 82°F during surveillance tests. The licensee determined that this maximum recorded temperature (82°F) is well within the maximum design temperature limit of the battery documented in the vendor manual of 107°F (Calculation R42-001, Addendum A-01, Revision 0). Additionally, the NRC staff notes, as described above, the ECA-75 analysis shows that Battery Room temperature will remain below the maximum battery component qualification temperature for the time period before ventilation is established.

As part of its evaluation, the licensee reviewed equipment subjected to FLEX BDBEE ambient conditions in the drywell (where the SRV's are located) and containment (where instrumentation critical to the FLEX strategies and the hydrogen igniter panel are located) to assess their functionality under elevated temperatures and pressures for the ELAP duration (i.e. end of the transient). In response, in SE.7 of the FIP, the licensee stated that the duration of the elevated temperatures during a BDBEE is less than or equal to 24 hours with peak temperature not exceeding 230°F at approximately 24 hours. The licensee's FIP submittal also indicates that the drywell temperature will not exceed 250°F. These conclusions are based on the analysis of the FLEX scenario in Calculation X11-001, Case 704 which determined that the Suppression Pool may reach 230°F at approximately 24 hours and then temperature starts decreasing by FLEX based actions. Calculation X11-001 shows containment temperature peaks at approximately 203°F with a slow downward trend until the end of the transient. The limiting design basis (DBA) thermal conditions for the drywell are for a small line break LOCA scenario and in this scenario, the drywell temperature will be 330°F for the first 3 hours, 310°F for the next 3 hours and 250°F for the next 24 hours. The licensee states that small break LOCA profile thus envelopes the postulated FLEX scenario regarding drywell temperature. Regarding FLEX equipment located in containment, the licensee stated during the audit that the containment temperature profile bounds all credited FLEX equipment except some components within the Hydrogen Igniter Panel. The licensee provided "Environmental Qualification Report of Class 1E Fuse Panels for Hydrogen Igniter System... Perry Nuclear Power Plant," Revision 0, dated May 7, 1985, to provide a basis for their expectation that this equipment would still function under a FLEX scenario.

The NRC staff notes that in addition to the licensee's peak temperature evaluations, the PNPP strategy provides for cooling of the Suppression Pool in Phase 2 to stabilize or establish a slowly decreasing temperature trend. Once the Phase 3 equipment is deployed, actions to provide a higher capacity cooling system (RHR), supported by a second FLEX lake water pump, if needed, will further reduce the Suppression Pool and Containment temperatures such that the credited equipment should function in the long-term to support the overall strategy. Based on the licensee's FIP statements and information reviewed during the audit process, as well as the long-term cooling strategy, the NRC staff finds that it is reasonable to assume that the equipment necessary to support the FLEX strategies will perform its intended function.

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

3.9.1.2 Loss of Heating

The battery rooms are in the interior of the Control Complex and are normally maintained at approximately 77°F. The licensee's FIP states that all FLEX equipment is stored in locations that provide protection from the extreme cold hazards at the site. During the audit process the licensee indicated that in the event of loss of heating during an ELAP, the battery room temperatures would be expected to rise with loss of ventilation. The licensee stated in the FIP that the battery design temperature limits are 25°F to 107°F per the battery vendor manual. Therefore, the licensee reaching the minimum temperature design limit is not expected.

Based on its review of the licensee's FIP, as well as the licensee's battery room assessment, the NRC staff finds that the PNPP batteries should perform their required functions at the expected temperatures as a result of loss of heating during an ELAP event.

3.9.1.3 Hydrogen Gas Control in Vital Battery Rooms

In order to assess the potential for hydrogen gas to accumulate into the battery rooms, the licensee calculated that the hydrogen concentration level would not reach 2 percent concentration for 14 days for Divisions 1 and 2, and 47 days for Division 3, if ventilation is not available. This analysis was performed in the licensee's Calculation R42-001, "Hydrogen Battery Production and the Hydrogen Gas Concentration in Division 1, 2 and 3 Battery Rooms Units 1 and 2," Revision 0. Further, the licensee stated in its FIP that battery room ventilation is restored prior to restoring the battery chargers.

The NRC staff reviewed the licensee's battery room hydrogen production analysis and did not identify any issues. Based on the licensee's FIP submittal, the NRC staff finds that it is reasonable for the licensee to conclude that hydrogen accumulation in the 125 Vdc Vital Battery Rooms will not reach the combustibility limit for hydrogen (2 percent) during an ELAP as a result of a BDBEE since power will be restored to the vital battery room HVAC systems prior to restoring the battery chargers and recharging the batteries.

3.9.2 Personnel Habitability

3.9.2.1 Main Control Room

To evaluate the environmental conditions in the Main Control Room following an ELAP-initiating event, the licensee performed an evaluation utilizing the GOTHIC 8.0 computer code in calculation X11-010, "Transient Thermal Analysis of the Control Room following an ELAP Scenario", Revision 0. The calculation determined that, when completing the appropriate actions delineated in station procedures (FSG 90.3, "Alternate Room Ventilation", mainly opening doors), the temperature rise in the Control Room would reach a maximum of 103°F dry-bulb temperature. This temperature was calculated for the warmest part of the day when outside air is being circulated into the Control Room by the repowered ventilation system. Based on the conservative manner in which the temperatures were calculated and the overall magnitude of the calculated temperatures, the NRC staff finds that it is reasonable to conclude that the environmental conditions anticipated in the Control Room following an ELAP-inducing event should not preclude the operators from performing their duties and carrying out the mitigating strategies.

3.9.2.2 Spent Fuel Pool Area

See Section 3.3.4.1.3 above for the detailed discussion of ventilation and habitability considerations in the SFP Area. In general, within the licensee's plans, there is no need for deployment of personnel into the SFP area. Conservatively, the doors from the fuel handling building to the outside on the east side of the plant will still be opened to provide a ventilation flow path. This action is administratively controlled, and the Timing and Deployment Timeline Table of the FIP shows that the action is expected to be completed within 2 hours of the ELAP-initiating event, prior to the plan's 4 hour time constraint; thus the NRC staff finds that it is reasonable for the licensee to conclude that personnel habibitability should not be a concern in the SFP area during an ELAP event.

3.9.2.3 Other Plant Areas

The FIP states that an evaluation of the temperature response in the RCIC pump room was performed using the GOTHIC 8.0 computer code in Calculation X11-003, "Transient Thermal Analysis of Auxiliary Building Following an ELAP Scenario," Revision 0. The calculation concluded that, with the RCIC room door opened within 1 hour of the initiating event and with a portable fan placed at the door of the room within 4 hours of the initiating event, the room would reach a maximum of 150°F. The staff noted that there are some local actions which must be taken in the RCIC room early on in the event; however, these actions can be accomplished before the room reaches the 150°F peak temperature. After the appropriate doors are propped open and hose connections made, continuous habitation in the RCIC room is not required to support the strategies.

The FIP did not identify any other critical locations which require habitability evaluations for operator actions to support fulfillment of the mitigating strategies.

3.9.3 Conclusions

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

3.10 Water Sources

3.10.1 Reactor Coolant System Make-up

In its FIP, the licensee described that make-up to the RPV is provided by the RCIC turbine-driven pump taking suction from the CST if available, or from the Suppression Pool if the CST is not available. The CST is not seismically qualified or missile hazard protected; however it is protected by a dike that is seismically qualified and missile hazard qualified. Thus, upon a failure of the CST during an event, the volume of water that was in the CST at the time of failure could be available. For some external events, such as flooding and all but the most catastrophic failures of the CST, the CST would be available for a period time to supply the RCIC system. If the CST is not available for use, the RCIC suction is aligned to the alternate suction from the Suppression Pool per existing operations procedure(s).

The licensee has performed an engineering evaluation of the RCIC system to confirm that the RCIC system is robust for all temperatures of the Suppression Pool that are expected during an ELAP and loss of normal access to the ultimate heat sink event. To minimize the challenge to the RCIC system in Phase 2, provisions are made to establish an alternative supply of cold water (<85°F) to the RCIC pump suction from various sources.

In its FIP, the licensee described that during Phase 2, heated water is pumped from the Suppression Pool to the RHR system back to the Suppression Pool using either the SPCU or ADHR pump (repowered by FLEX TGs). This provides a modified RHR SPC flow path called SPCLC. In the case that the CST is not available and the Suppression Pool cannot be maintained less than 185°F, a hose connection is provided on the RCIC suction. This allows the RCIC suction to be connected to the new FPCC return header connection in the Aux Building. Alternate sources of water to the RCIC alternate suction includes the SPCU or ADHR pumps with water through the RHR HXs (described above), or the Mix Bed/Two Bed demineralized water tanks.

The licensee also described that because the only robust water source installed at PNPP is the Suppression Pool, a long-term alternate source of water must be arranged during Phase 2. This source is water from Lake Erie (UHS) which is supplied by a FLEX Lake Water pump (powered by FLEX TGs) taking suction on the ESWPH suction bay via the Unit 2 ESW pump pedestal foundation. This is designed to provide 2500 to 3000 gpm into the ESW system. From this total flow, 1500 to 2000 gpm will be used to supply the RHR HXs in phase 2, approximately 250 gpm will be available to supply SFP make-up requirements, and approximately 250 gpm (average) will be available for use in the RCIC system to provide a robust alternative water source. The licensee further described that provisions have been made for the use of other robust and non-robust water sources of higher quality, if available. The water in the Suppression Pool and UHS will be used in Phase 3.

3.10.2 Suppression Pool Make-up

In its FIP, the licensee described that RPV make-up is supplied from the Suppression Pool via RCIC injection. The volume of the Suppression Pool is designed to provide for RPV make-up during a loss of ac power event. No make-up water to the Suppression Pool is anticipated during Phase 1 coping. In Phase 2 at about T=6 hours, electrical power is available to vital 480 Vac busses in Division 1 or Division 2. This electrical power will be used to initiate the SPMU system to transfer approximately 265,000 gallons of water from the upper pools to the Suppression Pool per the design function of the system. If the SPMU system is not available, inventory can be added to the Suppression Pool from the CST via gravity feed (if the CST remains available) or from ESW via the FLEX pumps in the ESWPH. The CST gravity drain is accomplished using normal plant piping and is not credited due to the CST not being "robust".

3.10.3 Spent Fuel Pool Make-up

In its FIP, the licensee described that make-up to the SFP is not anticipated in Phase 1. Make-up to the SFP in Phases 2 and 3 is from ESW as supplied from the FLEX Lake Water Pump(s). Hoses will be connected between the FLEX Lake Water Pump and installed Storz connectors on the ESW "A" Pump discharge piping (or alternately the ESW "B" Pump discharge piping) to allow the lake water to flow to the Auxiliary and Intermediate Buildings. A 10 inch supply line from ESW "A" runs through the Intermediate Building at Elevation 599 feet. This line will supply the SFP hose and spray requirements.

3.10.4 Containment Cooling

In its FIP, the licensee described that during Phase 1, the containment pressure and Suppression Pool temperature would increase to approximately 12 psig and 225°F, respectively, at T= 6 hours as the Suppression Pool water absorbs the reactor's decay heat and the operators partially depressurize to approximately 200 psig. This is within the containment design pressure of 15 psig, but exceeds the Suppression Pool temperature limit of 185°F. The containment Suppression Pool design temperature of 185°F will be exceeded before 6 hours regardless of the actions that can be taken in Phase 1. The structural impact of exceeding the Suppression Pool temperature limit is evaluated in Section 3.4.4.1.1 of this safety evaluation and the impact to RCIC is discussed in Sections 3.1, 3.2.1.1.2, and 3.2.2.1.1 of this safety evaluation.

The method of heat removal from the containment during Phase 2 is to perform SPCLC, which is a modified RHR SPC flow path. The SPCLC method of heat removal is established by establishing flow through the RHR system using either the SPCU pump or the ADHR pump to replace the RHR pump.

Cool water from the alternate water source and water from the upper containment pool can also be added to the Suppression Pool to increase inventory and reduce overall bulk temperature.

By Phase 3, 4160 Vac TGs will have arrived from the NSRC and will be connected to the distribution center in parallel with the on-site FLEX TGs or directly to the a critical bus needing to be energized if the distribution center is not available. Thus, RHR can be placed into service to allow additional heat removal capacity.

3.10.5 Conclusions

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

3.11 Shutdown and Refueling Analyses

Order EA-12-049 requires that licensees must be capable of implementing the mitigation strategies in all modes. In general, the discussion above focuses on a BDBEE occurring during power operations. This is appropriate, as plants typically operate at power for 90 percent or more of the year. When the BDBEE occurs with the plant at power, the mitigation strategy initially focuses on the use of a pump coupled to a steam-powered turbine 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 make-up 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 make-up to the SFP. In its FIP, the licensee described that SFP inventory make-up, at a flow rate of about 100 gpm, is estimated to be required at >26 hours with maximum heat load (following a full core off-load) after the event to ensure that the racks remain covered and the licensee has stated that they have the ability to implement make-up to the SFP within that time.

When a plant is in a shutdown mode in which steam is not available to operate the steam-powered pump such as RCIC (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 30], which described methods to ensure plant safety in those shutdown modes. By letter dated September 30, 2013 [Reference 31], 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 has concluded 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. In its FIP, the licensee stated that it conforms to the provisions of the NRC endorsed NEI position paper on Shutdown/Refueling Modes. Further, the licensee has developed an administrative program, NOP-LP-7300, "FLEX Program for the Perry Nuclear Power Plant (PNPP)," Revision 1, that includes provisions to maintain areas adjacent to the equipment storage and staging areas, as well as deployment and hose routing paths, clear at all times.

Based on the incorporation of the NRC-endorsed position paper into the FLEX program, 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, as endorsed, by JLD-ISG-2012-01, and should adequately address the requirements of the order.

3.12 Procedures and Training

Procedures

In its FIP, the licensee described that FENOC is a participant in the Boiling Water Reactor Owner Group-Emergency Procedures Committee (BWROG-EPC) and has implemented Emergency Procedure Guide/Severe Accident Guideline (EPG/SAG) Revision 3 for the EOPs that includes guidance for actions to preserve steam driven injection and protect the function of Primary Containment. The EPG/SAG Revision 3 also provides static guidance for implementation of FLEX Support Guidelines (FSGs) for restoring functions needed during the event to implement the EOPs. Additional Generic Off-Normal (ONI) Guidance has been developed to provide static guidance for restoration of vital electrical power and management of other functions that are not directly required to restore or maintain a function needed for the EOPs.

The licensee has revised ONI-R10, "Loss of Off-Site Power," which provided guidance for all events where connection to the grid is lost to the designated safety electrical busses. The station blackout guidance of ONI-R10 was relocated to ONI-R10-2, "Total Loss Of AC Power". In use, the EOPs and ONI-R10-2 are to be implemented in parallel to provide the strategic guidance for the event. Individual tactical procedures (FSGs, ONI-Special Plant Instructions (SPI), and EOP-SPIs) perform the tactical actions to accomplish the restoration or preservation of the required functions of NEI 12-06.

The licensee's FIP states that the procedural implementation strategy aligns with the procedure hierarchy described in NEI 12-06 in that actions that maneuver the plant are contained within the typical controlling procedure, and the FSGs are implemented as necessary to maintain the key safety functions of Core Cooling, Spent Fuel Cooling, and Containment Integrity in parallel with the controlling procedure actions. The overall approach is symptom-based, meaning that the controlling procedure actions and FSGs are implemented based upon actual plant conditions. The licensee incorporated the FSGs into existing plant procedures, via reference, in order to develop the FSG interface.

Training

In its FIP, the licensee stated that training plans were developed for plant groups. such as Emergency Response Organization (ERO), Security, Operations, Engineering, Mechanical Maintenance, and Electrical Maintenance. The training plan development was done in accordance with PNPP procedures using the Systematic Approach to Training (SAT).

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

3.13 Maintenance and Testing of FLEX Equipment

As a generic issue, NEI submitted a letter dated October 3, 2013 [Reference 32], which included EPRI Technical Report 3002000623, "Nuclear Maintenance Applications Center: Preventive Maintenance Basis for FLEX Equipment." In a letter dated October 7, 2013 [Reference 33], the NRC endorsed the use of the EPRI report and the EPRI database as providing a useful input for licensees to use in developing their maintenance and testing programs. Preventative maintenance templates for the major FLEX equipment have also been issued.

In its FIP, the licensee described that FLEX mitigation equipment has been initially tested (or other reasonable means used) to verify performance conforms to the limiting FLEX requirements. The testing included the equipment and the assembled sub-system to meet the planned FLEX performance. The licensee states in its FIP that development of the ERPI templates at the site will meet the FLEX guidelines [for maintenance and testing] established in NEI 12-06. In its FIP, the licensee further described that it has developed maintenance and testing templates specifically for the FLEX equipment and lists in the FIP appendix the initially identified tasks planned for the FLEX equipment.

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

3.14 Alternatives to NEI 12-06, Revision 0

In its FIP revision [Reference 52], the licensee has identified one alternative approach to the provisions of NEI 12-06, Revision 0, regarding spare 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 & cables, etc. NEI, on behalf of the commercial nuclear power industry, submitted a letter to the NRC [Reference 34] proposing an alternative regarding the quantity of spare hoses and cables to be stored on site. The alternative proposed was 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. Specifically, the revised FIP indicates that the licensee will utilize option (a). By letter dated May,18, 2015 [Reference 35], the NRC agreed that the alternative approach is reasonable, with certain conditions and clarifications. Specifically, NRC staff acknowledges that it is highly unlikely that a full set of hose and cable sections would be damaged while in storage or when being deployed and that using option (a) of the NEI proposal should result in the site having sufficient spare hoses and cables to implement the overall strategy. Based on the use of the alternative in accordance with the NRC's endorsement letter, the NRC staff approves this alternative for PNPP as an acceptable method of compliance with the order.

3.15 Conclusion 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 27, 2013 [Reference 36], the licensee submitted an OIP for PNPP in response to Order EA-12-051. By letter dated June 10, 2013 [Reference 37] the NRC staff sent a Request for Additional Information (RAI) to the licensee. The licensee provided a response by letter dated July 2, 2013 [Reference 38]. By letter dated December 11, 2013 [Reference 39], the NRC staff issued an ISE and RAI to the licensee.

By letters dated August 26, 2013 [Reference 40], February 27, 2014 [Reference 41], August 28, 2014 [Reference 42], and February 26, 2015 [Reference 43], the licensee submitted status reports for the Integrated Plan. The Integrated Plan describes the strategies and guidance to be implemented by the licensee for the installation of reliable Spent Fuel Pool Level Instrumentation (SFPLI) which will function following a BDBEE, including modifications necessary to support this implementation, pursuant to Order EA-12-051. By letter dated June 2, 2015 [Reference 44], the licensee reported that full compliance with the requirements of Order EA-12-051 was achieved.

The licensee installed a SFPLI system designed by Westinghouse, LLC. The NRC staff audited Westinghouse's SFPLI system design specifications, calculations and analyses, test plans, and test reports in support of the NRC staff review of licensees' OIPs in response to Order EA-12-051. The NRC issued an audit report regarding the Westinghouse level system on August 18, 2014 [Reference 45].

The NRC staff also conducted the onsite audit at the PNPP to review the licensee's implementation of SFPLI related to Order EA-12-051. The scope of the audit was to assess the licensee's progress toward order compliance and included verification of whether: (a) the site's seismic and environmental conditions are enveloped by the equipment qualifications, (b) equipment installation met the order requirements and vendor's recommendations, and (c) program features met the order requirements. By letter dated June 1, 2015 [Reference 18], the NRC issued an audit report on the licensee's progress.

4.1 Levels of Required Monitoring

Section 2.2 of this safety evaluation provides a description of the water levels which must be monitored in the SFP. Level 1 is the level that is adequate to support operation of the normal fuel pool cooling system. Level 2 is the level that is adequate to provide substantial radiation shielding for a person standing on the SFP operating deck. Level 3 is the level where fuel remains covered and actions to implement make-up water addition should no longer be deferred.

In its OIP, the licensee stated that:

> PNPP discharges irradiated fuel to a single spent fuel storage pool. With the exception of limited time periods for maintenance or non-refueling operations, administrative controls maintain gates in the open position between the following pools: fuel storage & preparation pool, fuel transfer pool, spent fuel storage pool, and cask pit. Thus, these pools are normally inter-connected and at the same water level when the water level in the spent fuel pool is greater than 3.5 feet above the top of stored fuel seated in the storage racks.
>
> The water levels for the SFP for the PNPP station will be determined based on the existing design attributes, commitments, and licensing basis of the station. This is also consistent with the NRC JLD-ISG-2012-03 and NEI 12-02 requirements. The proposed design for PNPP is based on the following key spent fuel pool water levels:
>
> *Level 1 - Level adequate to support operation of the normal fuel pool cooling system*
>
> Indicated level on either the primary or backup instrument channel of greater than elevation 619'-6" plus the accuracy of the SFP level instrument channel, which is to be determined. The highest point on the spent fuel pool racks is at elevation 591'-4".
>
> This level is based on the elevation of the skimmers that will prevent water transfer from the SFP to the Surge Tanks that feed normal spent fuel pool cooling. Once the water level in the pool drops below elevation 619'-6", water will no longer be extracted from the pool to be sent to Surge Tanks to provide water make up for Spent Fuel Pool Cooling.
>
> *Level 2 - Level adequate to provide substantial radiation shielding for a person standing on the spent fuel pool operating deck*
>
> Indicated level on either primary or backup instrument channel of greater than 601"4" plus the accuracy of the SFP level instrument channel, which is to be determined. This

monitoring level ensures there is an adequate water level to provide substantial radiation shielding for a person standing on the SFP operating deck.

This level was selected based on the NEI 12-02 Revision 1 guidance for selecting the plant specific elevation for Level 2 given as 10 feet (+/- 1 foot) above the highest point of any fuel rack seated in the spent fuel pool. This level will provide adequate radiation shielding for a person standing on the spent fuel pool operating deck from the fuel in the pool. However, the PNPP SFP contains other materials capable of providing sufficient dose such that the pool deck would not be inhabitable should the materials be uncovered. The detailed design will update or develop applicable plant procedures to address actions required to address radiological conditions created due to the stored radioactive material.

Level 3 - Level where fuel remains covered and actions to implement make-up water addition should no longer be deferred

Indicated level on either the primary or backup instrument channel of greater than 594'-6" plus the accuracy of the SFP level instrumentation, which is to be determined. This monitoring level assures that there is adequate water level above the stored fuel seated in the rack.

The top of the highest point on the spent fuel racks is located at 591'-4". The top of the gate seat that separates the two pools containing spent fuel (the fuel storage and preparation pool and the spent fuel storage pool) from the fuel transfer pool is at elevation 594'-6". Once the water drops below this point, the single SFP has effectively been segregated into four separate pits. Consequently, 594'-6" is the level at which actions to initiate water make-up will not be further delayed. This setting is in compliance with the Order; however, it represents a slight variation to the NEI guidance. The NEI guidance recommends using the top of the highest fuel rack in the spent fuel pool as level 3. The conditions described above make it undesirable to use top of the highest fuel rack as level 3. This is a conservative decision to treat 594'-6" as top of the fuel and necessary to ensure proper actions are taken in the event that one of the channels of SFP level instrumentation is lost or in the event that level is decreasing due to a hole in one of the pools.

By letter dated June 10, 2013 [Reference 37], the NRC staff sent a RAI to the licensee. In RAI-1 the NRC staff requested the following:

a. For Level 1, specify how the identified location represents the higher of the two points described in the NEI 12-02 guidance for this level.

b. The OIP states, "the PNPP SFP contains other materials capable of providing sufficient dose such that the pool deck would not be inhabitable should the materials be uncovered." Given the potential for varied dose rates from other materials stored in the SFP, describe how Level 2 will be adjusted to other than the elevation provided in Section 2, above.

c. A clearly labeled sketch depicting the elevation view of the proposed typical mounting arrangement for the portions of instrument channel consisting of permanent measurement channel equipment (e.g., fixed level sensors and/or stilling wells, and mounting brackets). Indicate on this sketch the datum values representing Level 1, Level 2, and Level 3, as well as the top of the fuel. Indicate on this sketch the portion of the level sensor measurement range that is sensitive to measurement of the fuel pool level, with respect to the Level 1, Level 2, and Level 3, datum points.

The licensee provided a response by letter dated July 2, 2013 [Reference 38], in which it stated that:

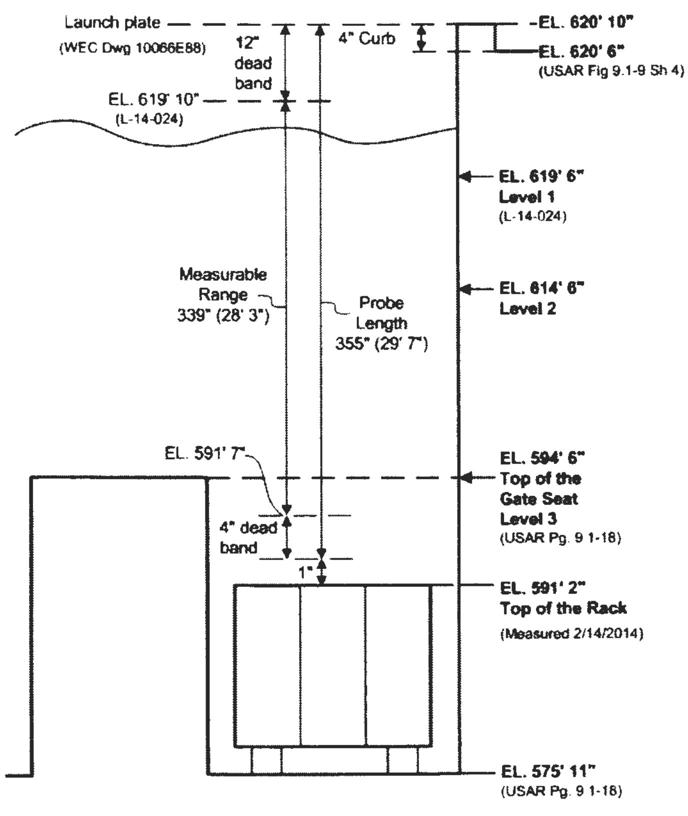
> No other means of removing water from the SFP exist above the skimmers. Therefore, the identified location is the highest point of the two options described in the NEI 12-02 guidance for Level 1 and is the level that is adequate to support operation of the normal fuel pool cooling system.
>
> NEI 12-02 allows the licensee to use 10 feet (+/- 1 foot) above the highest point of any fuel rack seated in the SFPs as Level 2. FENOC has chosen this option for PNPP. NEI 12-02, Section 2.3.2 states that "Level 2 represents the range of water level where any necessary operations in the vicinity of the SFP can be completed without significant dose consequences from direct gamma radiation from the stored spent fuel." Level 2 is associated with dose rates from the fuel; therefore, it is not adjusted based on varied dose rates from other items in the pool. FENOC has selected guided wave radar as its technology, which provides continuous level indication from Level 1 through Level 3. Data will be available for mitigation strategies to be initiated, when deemed appropriate, based on water levels between Level 1 and Level 3. FENOC recognizes additional materials stored in the SFP may cause the area to become uninhabitable prior to the monitored Level 2. FENOC also recognizes that the location of these additional materials is subject to change during each refueling outage. Therefore, FENOC does not plan to adjust Level 2, but instead address the potential dose rates associated with other material through alternate means. FENOC plans to evaluate the other materials in the SFP for relocation or removal in support of mitigation strategies. Based on fuel pool material configuration and projected dose levels, FENOC plans to develop an early method to keep those materials adequately covered using mitigation strategies or a manual make-up capability from a location not impacted by the dose rate. Mitigation strategies for addressing increased doses to personnel in the SFP area associated with other materials in the pool in a beyond-design-basis accident is to be addressed via PNPP FLEX procedures, as needed.

By letter dated August 28, 2014 [Reference 42], the licensee provided the change on Level 2 elevation as below:

> Level 2 was previously set as the indicated level on either the primary or backup instrument channel of greater than elevation (EL) 601' 4" plus the accuracy of the SFPLI channel which was to be determined. This level was selected based on the NEI 12-02, Revision 1, guidance for selecting the plant specific elevation for Level 2 given as 10 feet

(+/- 1 foot) above the highest point of any fuel rack seated in the SFP. This level provides adequate radiation shielding for a person standing on the SFP operating deck from the fuel in the pool; however, the PNPP SFP contains other materials capable of providing sufficient dose such that the pool deck would not be inhabitable should the materials be uncovered. To support the development of diverse and FLEX procedures, a site-specific radiation calculation was performed to determine a more appropriate Level 2 as it applies to FLEX mitigation strategies. As provided for in NEI 12-02, Revision 1, the calculation considered the emergency conditions that may apply at the time and the scope of necessary local operations, including installation of portable SFP instrument channel components. As a result, Level 2 has been reestablished as EL 614' 6".

In its compliance letter dated June 2, 2015 [Reference 44], the licensee provided a revised sketch showing Levels 1, 2, and 3, reproduced below:



[PNPP SFP Datum Value Sketch]

The NRC staff found the licensee selection of the SFP measurement levels adequate based on the following:

- Level 1, at elevation 619'-6", represents a level that, below which, water from the pool will no longer feed the surge tanks that provide water make-up for SFP cooling. Thus, the designated Level 1 setpoint would allow the licensee to identify a level in the SFP adequate to support long term operation of the normal SFP cooling system, and represents the higher of the two options described in NEI 12-02.

- Level 2, at elevation 614'-6", is conservatively higher than one of the options for meeting the NEI 12-02 guidance for Level 2 selection, to account for other non-fuel materials that may be stored in the SFP. The elevation selected meets both options described in NEI 12-02 for Level 2, which is 10 feet (+/- 1 foot) above the highest point of any fuel rack seated in the spent fuel pools or the level that provides adequate shielding for local operations in the vicinity of the pool. Therefore, the designated Level 2 will support identification of a level that provides substantial radiation shielding for a person standing on the SFP operating deck, consistent with NEI 12-02.

- Level 3, at elevation 594'-6", is approximately 3 feet above the highest point of any spent fuel storage rack seated in the SFP and aligned with the top of the gate that separates the two pools containing spent fuel. This level allows the licensee to initiate water make-up before the SFP is segregated in to four separate pits by the gate seat and is conservatively above the NEI 12-02 specified level of the highest point of the fuel racks seated in the SFP. Meeting the NEI 12-02 specificaiton of the highest point of the fuel racks conservatively meets the Order EA-12-051 requirement of a level where the fuel remains covered.

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, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.2 Evaluation of Design Features

Refer to Section 2.2 above for the requirements of the order in regards to the design features that are evaluated below.

4.2.1 Design Features: Instruments

In its OIP, the licensee stated that:

> The instrumentation will consist of permanent, fixed primary and backup instrument channels. The plan is for both channels to utilize guided wave radar, which functions according to the principle of time domain reflectometry. A generated pulse of electromagnetic energy travels down the probe. Upon reaching the liquid surface the pulse is reflected and based upon reflection times level is determined. Guided wave radar attributes:

- Cable assembly is a fixture located close to the operating level floor that suspends a cable into the pool. The guided wave radar cable assembly is smaller, and therefore is easier to protect from event generated missiles or falling objects.
- Guided wave radar is effectively immune to interference as the signal stays in the immediate vicinity of the wire antenna. As the cable assembly will be located close to the pool wall it is better protected from interference from foreign objects.
- This technology is immune to the changes in temperature or the specific gravity of the SFP water.
- Measured range will be continuous from the top of the SFP to the top of the spent fuel racks.

NEI 12-02 specifies that the instrument channels may be fixed or portable and that there be a primary and backup channel. Based on the licensee's OIP, which specifies fixed primary and backup channels, the NRC staff finds that the number of channels for its SFP is consistent with NEI 12-02, 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 planned design of this system will consist of two measurement channels, one primary and one backup. Each channel will consist of a level sensor, an electronics unit and an indicator. The primary and backup instrument channel sensors will be protected against missiles that may result from damage to the structure over the SFP. The sensors will be mounted at the western end of the fuel pool (the fuel preparation and storage pool), but as close to the adjacent corners as possible to minimize the possibility of a single event or missile damaging both channels. The sensor arrangement has been proposed in a manner limiting any interference with existing equipment in or around the SFP. This planned design is conservative and is in compliance with Order EA-12-051 however, it does represent a minor deviation from the NEI Guidance. The NEI Guidance recommends putting instrumentation in opposite (diagonal) ends of the spent fuel pool. Due to the limited available locations (caused by interference) for installation, the instrumentation cannot be installed on opposite (diagonal) ends of the pool. This planned design will also not pose any potential hazard to personnel working around the pool or on the level instrumentation itself.
>
> The proposed design locates the electronics enclosures in an area removed from the SFP environment, which would be accessible in the event of a beyond-design basis external event that would restrict access to the SFP. The enclosures for the two instrument channels will be separated to minimize the possibility of a single event damaging both channels. Cabling for each channel will be run in separate conduit and/or cable tray to the control room indicators.

The NRC staff noted that the licensee proposal deviates slightly from the guidance in NEI 12-02 by placing both the primary and backup instrumentation on the western side of the pool rather than in diagonally opposite corners. NEI 12-02 recommends mounting the sensors on opposite sides or corners of the pool area, if practical. However, based on the walkdown during the onsite audit, the NRC staff found that the sensor locations chosen are the only practical option, given the interference of the existing equipment in the pool, to maximize the separation. The locations use the adjacent corners as much as possible to provide protection and are physically separated to minimize the possibility of a single event or missile damaging both channels. The NRC staff thus concludes that the arrangement chosen provides sufficient channel separation within the SFP area between the primary and backup level instrument channels, 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 the licensee's arrangement for the SFPLI, if implemented appropriately, is consistent with NEI 12-02, 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:

> Installed primary and back up SFP level 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 in accordance with NRC JLD-ISG-2012-03 and NEI 12-02 Revision 1 guidance requirements.

By letter dated June 10, 2013, in ISE RAI-3, the staff requested the following:

- The design criteria that will be used to estimate the total loading on the mounting device(s), including static weight loads and dynamic loads. Describe the methodology that will be used to estimate the total loading, 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.

- A description of the manner in which the level sensor (and stilling well, if appropriate) will be attached to the refueling floor and/or other support structures for each planned point of attachment of the probe assembly. Indicate in a schematic the portions of the level sensor that will serve as points of attachment for mechanical/mounting or electrical connections.

- A description of the manner by which the mechanical connections will attach the level instrument to permanent SFP structures so as to support the level sensor assembly.

By letter dated February 27, 2014 [Reference 41], the licensee stated that:

> The mounting bracket for the sensing probe will be designed according to the plant Design basis, inclusive of loads from a Safe Shutdown Earthquake (SSE). Loads that will be considered in the evaluation of the bracket and its mounting are: 1) Static loads,

inclusive of the dead weight of the mounting bracket in addition to the weight of the level sensing instruments and cabling and 2) Dynamic loads, including the seismic load due to excitation of the dead weight of the system in addition to the hydrodynamic effects resulting from the excitation of the SFP water. A response spectra analysis will be performed for the seismic evaluation of the mounting bracket using a Finite Element Analysis (FEA) software and using floor response spectrum at the operating deck elevation (that is, mounting floor elevation). Damping values will be according to SSE and consistent with the design basis of the station. The material properties that will be used for the bracket and its mounting will take into consideration the environmental conditions in the SFP area following an event. Hydrodynamic effects on the mounting bracket will be evaluated using TID-7024 (Nuclear Reactors and Earthquakes, dated 1963). Plant acceptance criteria and applicable codes will be used for the design of the Bracket and its anchorage.

The bracket will be attached to the pool deck using installed anchors that will be designed according to the plant existing specification for design of concrete anchors. This is the only support for this instrument. The probe attaches to the bracket's support plate via a 1-1/2" NPT (National Pipe Thread Taper) threaded connection. Non-movable connections of parts will be welded. The specifics of the bracket design have yet to be finalized.

The attachment of the seismically qualified bracket to the pool deck will be through permanently installed anchors. With the permanently installed anchors, the bracket pedestal will be secured to the pool side deck with adequate washers and bolts.

During the onsite audit, the NRC staff reviewed Calculation CN-PEUS-13-27, "Seismic Analysis of the SFP Mounting Bracket at Perry Nuclear Power Plant," Revision 0, and Drawing 10066E88, "Perry Nuclear Generating Station Spent Fuel Pool Mounting Bracket Plan, Sections, and Details," Revision 0, and found that the design of mounting brackets for the sensing probes is adequate.

In ISE RAI-4 the NRC staff requested the results of the analyses used to verify the design criteria and methodology for seismic testing of the SFP instrumentation and the electronics units, including, design-basis maximum seismic loads and the hydrodynamic loads that could result from pool sloshing or other effects that could accompany such seismic forces.

During the onsite audit, the licensee provided a response, in which it stated that the results of the analysis and parameters used are contained in Westinghouse Calculation CN-PEUS-13-27, "Seismic Analysis of the SFP Mounting Bracket at Perry Nuclear Power Plant," Revision 0.

During the onsite audit, the NRC staff reviewed Calculation CN-PEUS-13-27 and found the following:

1. The calculation did not address the seismic evaluation for the mountings of the transmitters, electronics enclosures, pull boxes and conduits supports.

2. The sensing probe was not analyzed for the effects of hydrodynamic force.

In response to the NRC staff's concern, PNPP provided Report WNA-TR-03149-GEN, "Automation and Field Services SFPIS [spent fuel pool instrumentation system] Standard Product Final Summary Design Verification Report," Revision 2. In this report, Section 7.2, "Sloshing Justification," states that during the SFPIS product development, a sloshing calculation was performed to demonstrate that the probe would not be "sloshed" out of the SFP during the seismic event, LTR-SEE-II-13-47, "Determination if the Proposed Spent Fuel Pool Level Instrumentation can be sloshed out of the Spent Fuel Pool during a Seismic event," Revision 0. The NRC staff reviewed this evaluation and noted that PNPP's SFP probe includes a flexible cable and not a stiling well; therefore LTR-SEE-II-13-47, which analyzed the hydrodynamic effects for the stilling well design, is not applicable for PNPP. Thus, at the time of the onsite audit, PNPP had not demonstrated that the hydrodynamic forces will not impact the integrity and function of the probe.

In its compliance letter dated June 2, 2015 [Reference 44], the licensee provided a revised response to ISE RAI-4, in which it stated that:

> The results of the analysis and the parameters used are contained in Westinghouse calculation CN-PEUS-13-27, Revision 2, "Seismic Analysis of the SFP Mounting Bracket at Perry Nuclear Power Plant." The results are obtained from the GTSTRUDL [(structural analysis and design modeling software)] model and are in accordance with site design requirements and American Institute of Steel Construction (AISC) 7th Edition. Considering all of the applicable loads and load combinations, all members of the bracket are acceptable. All welds and bolts are acceptable when compared to their applicable allowable values. The results of the analysis represent all the applied loads and load combinations that were applied. The GTSTRUDL model and output considers self-weight, dead load of the instrumentation, hydrodynamic effects of the SFP water, and seismic load on the bracket. All members passed code check with interaction ratios below the allowable limit using the applicable requirements per AISC 7th Edition. Considering all of the loads and load combinations, all members of the bracket are acceptable. All welds and bolts are acceptable when compared to their applicable values.
>
> The seismic-related documents for the evaluation for the mounting of the electronic components and conduits were made available for NRC review. These documents included: Engineering Change Package (ECP) 12-0835-000, Fukushima Spent Fuel Pool Level Instrumentation Design, ECP 12-0835-002, Primary Channel wiring, cables, conduits, trays, supports and equipment from the SFP area and to the Main Control Room, ECP 12-0835-005, Backup Channel wiring, cables, conduits, trays, supports and equipment from the SFP area and to the MCR; Calculations 7:24.000, Spent Fuel Pool Level Instrumentation Equipment Mounting, OP42-0111, Self Weight Excitation Review of Hangers for Emergency Closed Cooling System, and 5:18.000, Spent Fuel Pool Level Instrumentation Mounting Anchor Qualification; Vendor Technical Information; Vendor Manual 1440; Qualification Reports; and Drawings. These documents demonstrate that the design for the mounting of electronic components and

> conduits was completed in accordance with the endorsed guidance in IEEE Standard 344-2004, "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations."
>
> The PNPP specific wave height due to sloshing is 4.45 feet maximum. This value is documented in CN-PEUS-13-27, Section 4.5.2.3, and is based on TID-7024. This 4.45 feet value is bound by the 5-foot value considered in the generic qualitative analysis performed for the level sensing probe documented in LTR-SEE-11-13-4 7. The PNPP specific value for the distance from the bracket to the nominal water level is 16 inches, which is greater than the 12 inches used in the generic analysis performed by Westinghouse (LTR-SEE-11-13-47). Westinghouse and PNPP engineering have assessed the PNPP specific parameters by estimating the change in the postulated hydrodynamic load on the level sensor combined with the design loads resulting in an estimated maximum anchor tension of approximately 1530 pounds. Review of the postulated load has confirmed that it remains within the allowable limit of 2000 lbs. for the 1/2 inch anchors, affirming the general conclusions of LTR-SEE-11-13-047 that the resulting loads on the level sensor probe will not result in probe ejection or potential impact of the instrument on the side walls.

The NRC staff found the revised response adequately addressed the staff's concern regarding the hydrodynamic effect on the SFPI probe and its mounting bracket.

In ISE RAI-5, the NRC staff requested description of the design inputs, and the methodology that will be used to qualify the structural integrity of the affected structures/equipment for each of the mounting attachments required to attach SFP Level equipment to plant structures.

By letter dated February 27, 2014 [Reference 41], the licensee stated that:

> Westinghouse has conducted seismic testing of the level sensor electronics bracket and electronics enclosure, which includes the mounting details, according to IEEE Standard 344 (2004), against the seismic spectra defined in the product design specification. All steel plates will conform to ASTM Standard A240 Type 304 steel. All bolts will conform to ASTM Standard F593C. All weld material will be the same as base metal or compatible. Loads applied consist of self-weight, dead load of the instrumentation (the probe assembly including the launch plate), seismic load, and hydrodynamic load due to the seismic effect. The seismic loads are obtained from plant response spectra curves. Convective pressure associated with hydrodynamic loads will be considered for sloshing analysis by conservatively using the longest span of the pool and the height of the water between the top of the fuel racks and the high water level since the bracket cantilevers over the SFP water. The calculation of the convective pressure is based on TID-7024. Load combinations will be used in accordance with plant seismic criteria. Seismic forces in all three directions are combined using GTSTRUDL analysis, Version 32. Dead weight, seismic and convective pressure results are combined in

> absolute values. The FENOC engineering change process will be used to address the effect of this added instrumentation to plant structures, and it will be analyzed per the plant design basis for equipment loads.

The NRC staff reviewed the mounting specifications for the SFP level instrumentation, including the methodology and design criteria used to estimate the total loading on the mounting devices. The staff also reviewed the design inputs and the methodology used to qualify the structural integrity of the affected structures/equipment for each of the SFP Level mounting attachments. Based on that review, the staff found that the criteria established by the licensee adequately accounted for the appropriate structural loading conditions, including seismic and hydrodynamic loads.

Based on the discussion above, the NRC staff finds the licensee's proposed mounting design is consistent with NEI 12-02, 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 that:

> The primary and backup instrumentation for the proposed design will be suitable and reliable at temperature, humidity, and radiation levels consistent with the SFP water at saturated conditions for an extended period of time. This reliability will be established through use of an augmented quality assurance process. Using the guidance of NEI 12-02, Revision 1 and NRC JLD-ISG-2012-03 the equipment design will include reliability against effects of shock and vibration and seismic motion.
>
> The design will consider the environmental conditions as discussed by NEI 12-02, Revision 1 which recommends considering temperature, humidity, and radiation levels during normal operation and after a beyond design basis external event for no fewer than seven days post-event or until off-site resources can be deployed by the mitigating strategies. Conditions considered are the radiological conditions for a normal refueling quantity of freshly discharged (100 hours) fuel with SFP water level at Level 3 as defined by NRC Order EA-12-051, temperatures of 212 °F and 100% relative humidity, boiling water and/or steam, and concentrated borated water.
>
> The sensor elements of the guided wave radar approach will consist solely of special cable that will not be negatively impacted by the environmental conditions described.
>
> The electronic enclosures will be mounted in an area outside the SFP area that is accessible by personnel after a beyond design basis external event and is expected to be a mild environment. The analog indicator will be mounted in the main control room, and as such will be suitable for the environmental conditions of the main control room following a beyond design basis external event. The

> vendor supplied sensors and Associated electronics will be required to be tested and qualified for shock and vibration as a result of a beyond design basis external event. Seismic qualification of equipment will be equivalent to the maximum ground motion spectrum for the area in which it is to be installed.

In ISE RAI-6 and RAI-7 the NRC staff requested the following:

- A description of the specific method or combination of methods that will be applied to demonstrate the reliability of the permanently installed equipment under beyond design basis ambient temperature, humidity, shock, vibration, and radiation conditions.

- A description of the testing and/or analyses that will be conducted to provide assurance that the equipment will perform reliably under the worst-case credible design basis loading at the location where the equipment will be mounted. Include a discussion of this seismic reliability demonstration as it applies to a) the level sensor mounted in the SFP area, and b) any control boxes, electronics, or read-out and re- transmitting devices that will be employed to convey the level information from the level sensor to the plant operators or emergency responders.

- A description of the specific method or combination of methods that will be used to confirm the reliability of the permanently installed equipment such that following a seismic event the instrument will maintain its required accuracy.

- The results from the selected methods, tests and analyses used to demonstrate the qualification and reliability of the installed equipment in accordance with the Order requirements.

During the onsite audit, the licensee provided a response, in which it stated that:

> Westinghouse methodologies for demonstrating the reliability of the installed SFP level instrumentation system are described in Westinghouse report EQ-QR-269, Revision 1, "Design Verification Testing Summary Report for the Spent Fuel Pool Instrumentation System," and Westinghouse report EQ-QR-264, Revision 0, "Equipment Qualification Abbreviated Summary Report for the Spent Fuel Pool Instrumentation System".
>
> Environmental qualification testing was performed in accordance with IEEE Std. 323-2003 and electromagnetic compatibility (EMC) qualification testing was performed in accordance with the technical requirements of Regulatory Guide 1.180.
>
> Temperature and Humidity - Thermal aging and steam testing were performed on the coaxial cables and couplers using a thermal aging oven at a temperature of 212°F for the calculated age duration of 311 hours plus 10% margin, or 343 hours and at 219°F for 206.5 hours plus a 10% margin, or 228 hours. The coaxial cables and couplers were coiled and set on separate racks in the thermal oven. The coupler was required to be threaded into the non-preconditioned end of the cable and aged as one assembly. Steam testing was performed in accordance with IEEE Std. 323-2003. The test specimen was exposed to 212°F (+/- 1.8°F), 100% saturated (+0, -2%) for a duration

including 10% margin of 185 hours. In addition, the connectors were splash tested to determine the appropriate torque level and sealing.

Regarding components outside the SFP area, Westinghouse concluded the aggregate of the environmental verification activities for the SFP instrumentation demonstrate that the instrumentation operates reliably in accordance with the service environmental requirements specified for both the harsh and outside SFP area conditions. The level sensor electronics housing was also verified to meet IP67 rating per EPSILON 08 TEST 2373, which will prevent water ingress and withstand 100 percent humidity.

Shock and Vibration - Seismic testing consisted of five successful OBE tests, two successful SSE tests, and one successful HRHF [Hard Rock High Frequency] test. During the second successful SSE level test (281 SSE 2), AC power was cut off to the SFP instrumentation system to ensure that the UPS would reliably switch during a seismic event. No equipment failures were noted as a result of the seismic test runs. Westinghouse performed functional testing of the equipment before and after each SSE and HRHF runs, and the equipment maintained its functionality. In addition, Westinghouse inspected the equipment after the seismic testing and no damage was found. Westinghouse concluded that the system met all requirements, maintained structural integrity during and after all OBEs, SSEs and HRHF tests.

Radiation – The coaxial cable and coupler underwent radiation aging in accordance with IEEE Std. 323-2003 for service in post-accident radiation conditions. Test specimens were required to be exposed to a minimum of 11 Mrad of Co60 gamma rays at a dose rate minimum of 0.2 - 0.5 Mrad/hour.

EMC - Susceptibility, emissions and harmonics testing was performed and the guidance and limits provided in RG 1.180 were used. Continuous monitoring was performed to monitor the performance during the application of EMC susceptibility testing. Performance Criterion for this system is determined to be Criterion B.

Seismic qualification testing was performed in accordance with IEEE Std. 344-2004, which is endorsed by RG 1.100, Revision 3, and IEEE Std. 323-2003. The electronics enclosure was mounted to the test fixture with four 3/8-inch Grade 5 bolts, lock washers, flat washers, and nuts torqued snug tight. The sensor head unit mounting bracket was mounted to the fixture with four 3/8-inch Grade 5 bolts, lock washers, and flat washers torqued snug tight. The sensor head unit was mounted to the sensor head unit mounting bracket with two 1/4 inch-20 bolts and lock washers torqued to 75 in-lbs. The coaxial coupler was torqued hand tight. The launch plate was mounted to the fixture with four 5/16-inch Grade 5 bolts and lock washers torqued snug tight. The sensor head unit mounting bracket was mounted to the coupler using the integral threads in the probe and a lock washer to snug tight. Terminal block attachments within the rear of the sensor head unit were torqued to 8 in-lbs.

Seismic testing was performed on a 4x4-foot independent triaxial test table using random, multi-frequency acceleration time history inputs. Accelerometers were mounted on the test table and equipment under test. The table drive signal was applied separately and simultaneously in both the horizontal and vertical directions for a duration of 30 seconds with a minimum of 20 seconds of strong motion. The response from the table and the response accelerometers were analyzed at 5% critical dampening for each OBE and SSE test and were plotted at one twelfth octave intervals over the frequency range of 1 to 100 Hz.

Seismic testing of the instrumentation was performed in accordance with IEEE Std. 344-2004. The required response spectra (RRS) included a 10% margin recommended by IEEE Std. 323-2003. Seismic testing was performed to the defined SSE and HRHF spectra. The OBE RRS at 5% critical damping was at least 70% of the respective SSE seismic level. At a minimum, five successful OBE level tests were required, followed by two successful SSE level tests and one successful HRHF level test. In addition, static pull tests were performed on the Radiall connectors (straight and 90 degree) to address seismic qualification of the connectors.

The equipment under test (EUT) was powered on during OBE seismic test runs, but was not electrically monitored during the test runs. Functional testing was performed before and after the five successful OBE test runs. The system maintained accuracy after five successful OBE level tests and no loss of power was noted during the test runs. The EUT was powered on during all SSE and HRHF seismic test runs, but was not electrically monitored during the test runs. Functional testing was also performed before and after each successful SSE and HRHF test run. The system maintained accuracy after all SSE and HRHF level tests and no loss of power was noted during the test runs.

During the SSE 2, the alternating current (AC) power was removed from the system approximately 15 seconds into the run. This operation was performed to ensure that the uninterruptible power supply (UPS) was able to switch from line power to battery power during a seismic event. The system performed without issue. The EUT met all of the required performance and acceptance criteria and maintained structural integrity during all acceptable OBE test runs, acceptable SSE test runs, and the acceptable HRHF test run to the RRS. Acceptable functionality of the EUT was confirmed upon completion of seismic testing. The post-test inspection performed upon completion of all seismic tests revealed no major structural issues or damage to the EUT.

This response was documented in the licensee's compliance letter dated June 2, 2015 [Reference 44]. Based on this response, the NRC staff was unable to confirm that the environmental conditions at the PNPP's SFPLI equipment locations are enveloped by the vendor's equipment qualification.

In response to this NRC staff concern, as well as a similar question about the analog indicators, Weschler, Model VX-252, installed in the control room, the licensee provided the following during the onsite audit:

Calculation ECA-007, "Determine a Steady State Temperature Profile for Zone FB-4 Under Various Operating Conditions," Revision 1, which shows that the temperature increase in the Intermediate Building El. 654'-6" as a result of ECP 12-0835 is calculated to be approximately 0.1 °F.

> Drawing 022-0041-00000, "Environmental Conditions for Intermediate Building," Revision G, which shows Zone FB-4 where the SFPIS electronic components are located. This has expected 130 °F and 90% humidity for abnormal condition and 8.8 $x10^2$ Rads for 40 years of normal condition and 5.26 $x10^2$ Rads for 180 days of accident condition.
>
> Engineering Change Package 12-0835-001, Revision 3, which shows the SFPIS equipment will be seismically mounted to the plant structures with specified torques per WNA-IG-00452-GEN, "Spent Fuel Pool Instrumentation System Torque Specification," Revision 3, to ensure the equipment meets the shock and vibration justification made by Westinghouse.
>
> Report S0020.0, "Seismic Test Report for a Namco Limit Switch and a Weschler Indicator," Revision 2, which shows the indicator is seismically qualified.
>
> Purchase Order No. 45457881 CO.2 which shows that the indicator located in the Control Room, Weschler Model VX-252 is designed for mild environment with 89 °F max., 90 percent humidity max., 1.8 $x10^2$ Rads for normal condition and 5.0 Rads for 180 days of accident condition.

Based on this additional information, the NRC staff was able to evaluate the SFP level instrumentation qualification requirements including temperature, humidity, radiation, shock and vibration and found that the instrumentation is suitable for the environments where they are located. The control room has a mild environment and its environmental conditions envelope the environmental qualifications of the Weschler indicator, Model VX-252. Therefore, the NRC found that the Weschler Model VX-252 is suitable for the control room environment.

The NRC staff also learned during the audit that PNPP utilizes the modified straight connectors for the SFPI cables. In the final compliance letter [Reference 44], the licensee provided the following information:

> Westinghouse concluded that the probe, coaxial cable, 90 degree and straight connector, and stainless steel coupler are able to perform in abnormal conditions in the SFP area for up to seven days. In addition, Westinghouse tests demonstrated that the level sensor electronics with the coupler and the coaxial cable attached performs accurately when the probe, coupler, and coaxial cable are exposed to a temperature range of 10 to 100°C (50 to 212°F) and up to 100 percent relative humidity (RH).
>
> In addition, Westinghouse completed their 10-year aging test. The purpose of the testing was to extend the existing qualified life from 15 months to 10 years. The system with the 90 degree connector passed the test and is now qualified to a 10-year life. The system with the straight connector performed during the 7 days of steam testing, but functionality was lost during the final ramp down at the end of the 7 days. The PNPP design uses the straight connector. Westinghouse recommended that those plants using the straight connector continue with

> installation since the connector is qualified for 15 months. Westinghouse issued CAPAL 100045159 and FENOC issued Condition Report 2014-14616 in their respective corrective action programs to track resolution of this issue. In December 2014, Westinghouse notified FENOC that a follow-up test was performed, and the straight connector passed the test with Raychem added. Raychem will be added to the PNPP straight connector. The straight connector is now qualified for 10 years.

The NRC staff found that the supplemental information adequately demonstrates that the SFPLI equipment will be installed in locations where the environmental conditions are enveloped by the manufacturer's specifications and qualifications.

During the onsite audit, the NRC staff also inquired an assessment of potential susceptibilities of electromagnetic/radiofrequency interference in the areas where the SFP instrument located and how to mitigate those susceptibilities. The licensee provided a response, in which it stated that environmental testing was performed in accordance with IEEE Std. 323-2003 and EMC qualification testing was performed in accordance with RG 1.180. The SFPLI system utilizes tracer wire running along the coaxial cable from the bracket to the transmitter. Conduit is also used within the Fuel Handling Building (FHB). Additional testing was performed at the Factory Acceptance Test where portable radios were used in the vicinity of the equipment. This testing determined that there was no impact to the equipment further than 5 feet away. The signal always returned to normal after the radio transmission ended. To ensure that the equipment is not impacted by radio transmissions, a 15-foot exclusion zone is being established for both probe/bracket area (FHB El. 620') and the electronics enclosure/transmitter areas (Intermediate Building El. 654'). Signs are posted within view in each area.

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

4.2.5 <u>Design Features: Independence</u>

In its OIP, the licensee stated that:

> The primary instrument channel will be independent of the backup instrument channel. The primary and backup instrument channels will be physically and electrically separated to maintain channel independence. The sensors will be separated as far apart as practical within the constraints of existing pool geometry and equipment. Electronics enclosures will be separated by a suitable distance or may utilize structural features of the room in which they are located as a barrier to provide protection against a single event (missile, explosion, etc.) from damaging the electronics of both instrument channels. Power will be supplied from two separate power buses at a minimum, with a preference of different power divisions or channels as available. Cabling will be run in separate conduit and/or cable tray. The same technology will be used for both the primary and backup instrument channels.

In ISE RAI-8, the NRC staff requested the following:

- A description of how the two channels of the proposed level measurement system meet this requirement so that the potential for a common cause event to adversely affect both channels is minimized to the extent practicable.

- Further information describing the design and installation of each level measurement system, consisting of level sensor electronics, cabling, and readout devices. Please address how independence of these components of the primary and back-up channels is achieved through the application of independent power sources, physical and spatial separation, independence of signals sent to the location(s) of the readout devices, and the independence of the displays.

By letter dated February 27, 2014 [Reference 41], the licensee stated that:

> Within the Unit 1 SFP area, the brackets will be mounted as close to the northeast (primary sensor) and southwest (back-up sensor) corners of the SFP, as permanent plant structures allow. Within the Unit 2 SFP area, the brackets will be mounted as close to the southwest (primary sensor) and northeast (back-up sensor) corners of the SFP, as permanent plant structures allow. Placing the brackets and probes in the corners allows for natural protection from a single event or missile from disabling both systems. The cabling within the SFP area will be routed in separate hard-pipe conduit. All conduit routing and location of system components will be selected such that there will not be any seismic 2-over-1 hazard. Site safety related separation requirements will be followed.
>
> Each system will be installed using completely independent cabling structures, including routing of the interconnecting cable within the SFP area in separate hard-pipe including routing of the interconnecting cable within the SFP area in separate hard-pipe conduits. Power sources will be routed to the electronics enclosures from electrically separated sources ensuring the loss of one train or bus will not disable both channels. The system displays will be installed in separate qualified National Electrical Manufacturers Association (NEMA) Type 4X or better enclosures in the Unit 1 Auxiliary Building El. 752' 6" and the Unit 2 Auxiliary Building El. 755' 6", with the primary and back-up display in the main control room. Primary and backup systems will be completely independent of each other, having no shared components.

During the onsite audit, the licensee also provided Supplement 007 of Engineering Change Package 12-0835-000, "Fukushima Spent Fuel Pool (SFP) Level Instrumentation Design," Revision 3, that installs the FLEX SFPLI dual receptacle fed by the FLEX backed Lighting Panel. The receptacle can be used as an alternate power source in the case that the primary power to the electronics enclosure is lost.

The NRC staff noted that the combination of the licensee's OIP, RAI-8 response, and audit information adequately addressed the instrument channel independence, including the power sources. With the licensee's proposed power arrangement, the electrical functional performance of each level measurement channel would be considered independent of the other channel, and the loss of one power supply would not affect the operation of other independent channel under BDB event conditions. The instrument channels' physical separation is discussed in Section 4.2.2 of this safety evaluation.

Based on the discussion above and verification during the onsite audit walkdown, the NRC staff finds the licensee's proposed design, with respect to instrument channel independence, is consistent with NEI 12-02, 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 that:

> Each channel will normally be powered from independent 120 VAC power sources and will have a dedicated battery backup. A minimum battery life of 24 hours will be provided to allow for power restoration from portable equipment.

In ISE RAI-9, the NRC staff requested the following:

- A description of the electrical AC power sources and capabilities for the primary and backup channels.
- 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.

By letter dated February 27, 2014 [Reference 41], the licensee stated that:

> Each instrument channel is normally powered by non-class 1E 120 volts alternating current (AC) distribution panels to support continuous monitoring of the SFP level. The 120 VAC distribution panels for the primary and backup channels at each unit 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 120VAC power, each channel's uninterruptible power supply (UPS) automatically transfers to a dedicated backup battery. If normal power is restored, then the channel will automatically transfer back to the normal AC power. The 72-hour backup batteries are maintained in a charged state by UPSs.

NEI 12-02 specifies that electrical power for each channel be provided by different sources and that all channels have the capability of being connected to a source of power independent of the normal plant power systems. The NRC staff reviewed the power supply configuration and noted that upon a loss of normal power, the UPS arrangement would provide power for level indication, separate for each channel, until such time as the power is restored by portable TGs provided for Order EA-12-049.

Based on the licensee's OIP and RAI-9 response, the NRC staff finds that the licensee's proposed power supply design is consistent with NEI 12-02, 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 that:

> The guided wave radar design provides continuous monitoring of the SFP water level. The accuracy of the SFP level instrument channel, from sensor to main control room indicator, will be consistent with the guidelines of NRC JLD-ISG-2012-03 and NEI 12-02, Revision 1. Instrument channels will be designed to maintain their design accuracy without recalibration following a power interruption or change in power source.

In ISE RAI-10, the NRC staff requested the following:

- An estimate of the expected instrument channel accuracy performance (e.g., in percent of span) under both (a) normal SFP level conditions (approximately Level 1 or higher) and (b) at the BDB conditions (i.e., radiation, temperature, humidity, post-seismic and post-shock conditions) that would be present if the SFP level were at the Level 2 and Level 3 datum points.

- 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.

During the onsite audit, and in the final compliance letter [Reference 44], the licensee provided the following response:

> The design accuracy is 3 inches or less for both normal and BDB conditions and the calculated accuracy for PNPP of 1.83 inches is within the design range. The calculated accuracy of the instrumentation is 0.54 percent and the calculated accuracy of the control room indicator is 0.7082 percent.
>
> A periodic calibration verification will be performed within 60 days of a refueling outage considering normal testing scheduling allowances (for example, 25 percent). Calibration verification will not be required to be performed more than once per 12 months. These calibration requirements are consistent with the guidance provided in NEI 12-02, Section 4.3. Per Westinghouse procedures, should the calibration verification indicate that the instrument is out of tolerance by more than the designed 3-inch tolerance, a recalibration will be performed.

The NRC staff noted that the licensee adequately addressed instrument channel accuracy through a combination of statements in the OIP and in the final compliance letter. The 3-inch design accuracy is more conservative than the 1-foot accuracy specified by NEI 12-02 for SFP Levels 2 and 3. With the licensee's proposed design and controls, the instrument channels should maintain their accuracy during both normal and BDB conditions.

Based on the discussion above, the NRC staff finds the licensee's proposed instrument accuracy is consistent with NEI 12-02, 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 that:

> Testing will be consistent with the guidelines of NRC JLD-ISG-2012-03 and NEI 12-02, Revision 1. The instrument channel design will include provisions for routine testing and calibration. The instrumentation will allow for in-situ testing and calibration of the level instrumentation to minimize calibration effort and instrument downtime. Calibration procedures will be developed in accordance with plant procedures and vendor recommendations.

In ISE RAI-11, the NRC staff requested the following:

- A description of the capability and provisions the proposed level sensing equipment will have to enable periodic testing and calibration, including how this capability enables the equipment to be tested in-situ.
- A description of how such testing and calibration will enable the conduct of regular channel checks of each independent channel against the other, and against any other permanently-installed SFP level instrumentation.
- A description of how calibration tests and functional checks will be performed, and the frequency at which they will be conducted. Discuss how these surveillances will be incorporated into the plant surveillance program.
- A description of the preventive maintenance tasks required to be performed during normal operation, and the planned maximum surveillance interval that is necessary to ensure that the channels are fully conditioned to accurately and reliably perform their functions when needed.

During the onsite audit, the licensee provided a response, in which it stated that:

> Periodic calibration verification [CV] will be performed in-situ to verify that the transmitter is in calibration using a CV tool provided by the manufacturer and in accordance with the plant procedures and manufacturer's recommendations. Should the CV indicate that the transmitter is out of calibration, a full-range calibration adjustment will be completed using the calibration test kit. FENOC will perform periodic CVs using a periodic maintenance procedure and manufacturer's guidelines. The periodic CV will be performed within 60 days of a

> refueling outage. Preventive maintenance procedures will be in place for the periodic replacement of the backup batteries based on manufacturer recommendations and for CV.

The licensee also stated that channel checks are not a specified requirement in NEI 12-02.

The NRC staff disagreed with the licensee's position regarding channel check requirements. Specifically, Order EA-12-051 requires that reliable SFP level indication channels be provided and that "processes be established ... to maintain the instrument channels at design accuracy." The NRC staff position is that periodic monitoring of channel performance is a necessary element of a process that ensures that the instrumentation channels are maintained at their design accuracy.

In its compliance letter, the licensee provided a revised response, in which it stated that:

> A periodic calibration verification will be performed in-situ to verify that the transmitter is in calibration using a calibration verification tool provided by the manufacturer and in accordance with the plant procedures and manufacturer's recommendations. Should the calibration verification indicate that the transmitter is out of calibration, a full-range calibration adjustment will be completed using a calibration test kit. The portable test kit is composed of a replicate probe, coupler and launch plate equivalent to those installed, a replicate coaxial cable of the same electrical length as installed in the pool, a bracket to hold the weight end of the probe cable, simulated pool liner, and a moveable metal target. To perform the calibration, the installed SFP instrumentation system coaxial cable is disconnected from the sensor and the replicate test kit coaxial cable is connected. A metal target is used to measure several points along the length of the probe to perform the full-range calibration. The readings displayed on the output display at each point along the probe will be compared to the physical distance measured along the length of the probe cable to determine calibration acceptance. Each component in the instrument channel can be replaced (transmitter included) to restore the instrument loop to service in the event a component failure occurs.
>
> A channel check is conducted as part of ICI-801-012, ABB/K-TEK MT5000 Guided Wave Radar Level Transmitter Calibration Check, Section 5.4, to ensure that upon completion of the calibration check or calibration that the two channels compare within acceptable limits. The SFP level indication is located in the main control room. To aid in early detection of any "off normal" readings which could indicate that channel adjustment may be required, a periodic channel check using this indication of SFP level has been added to "Control Room Plant Equipment Rounds" and is conducted per OAI-1702, "Operations Section Rounds Sheets, Logs, and Records." The channel check is performed daily and confirms that the two SFP level instruments are reading within one foot of each other. As installed, the level instruments typically read within approximately 1/2 foot of each other (±3 inches calibration tolerance for each instrument) and the instrument scale reading is in 1/2 foot increments, establishing the basis of one

> scale unit divergence (1/2 foot) for the one foot channel check acceptance criteria. The channel check periodicity and acceptance criteria are controlled within PNPP operating procedures and periodic maintenance programs and may change based on equipment operating experience. Testing to validate instrument functionality per NEI 12-02, Section 4.3, is based on the instrument calibration periodicity.
>
> FENOC will perform periodic calibration verifications using periodic maintenance procedures and manufacturer's guidelines. The periodic calibration verification will be performed within 60 days of a refueling outage considering normal testing scheduling allowances (for example, 25 percent). Calibration verification will not be required to be performed more than once per 12 months. These calibration requirements are consistent with the guidance provided in NEI 12-02, Section 4.3.
>
> Preventive Maintenance (PM) procedures will be in place for periodic replacement of the backup batteries based on manufacturer recommendations and for calibration verification.

In accordance with the licensee's final compliance letter, the NRC staff notes that by comparing the levels in the instrument channels and the maximum allowed level deviation, the operators could determine if recalibration or troubleshooting is needed. The staff also notes that the licensee's proposed design has the ability to be tested and calibrated in-situ, consistent with the provisions of NEI 12-02.

Based on the discussion above, the NRC staff finds the licensee's proposed SFP instrumentation design allows for testing consistent with NEI 12-02, 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 display will be consistent with the guidelines of NRC JLD-ISG-2012-03 and NEI 12-02 Revision 1. Trained personnel will, at a minimum, be able to monitor the SFP water level from an appropriate and accessible location, and will provide on demand or continuous indication of SFP water level. The SFP level instrumentation will provide for display of fuel pool level using an indicator located in the main control room. The indicator will be powered by the instrument loop and will not require additional power circuits from those described above.

NEI 12-02 specifies that the SFP level indication be displayed at an appropriate and accessible location, such as the main control room. Since the licensee has installed the indicators in the main control room, where they are able to be monitored by trained personnel, the NRC staff finds that the licensee's proposed location and design of the SFP instrumentation displays is consistent with NEI 12-02, as endorsed by JLD-ISG-2012-03, and should adequately address the requirements of the order.

4.3 Evaluation of Programmatic Controls

4.3.1 Programmatic Controls: Training

In its OIP, the licensee stated that:

> The Systematic Approach to Training will be utilized when developing and Implementing training. Training for maintenance and operations personnel will be developed and provided. Training will be provided for the personnel in the use of, and provision of alternate power to, primary and backup instrument channels in compliance with the NRC Order EA-12-051 Attachment 2, Section 2.1.

NEI 12-02 specifies that the Systematic Approach to Training process be used to identify the population to be trained, and also to determine both the initial and continuing elements of the required training. Based on the licensee's OIP statement above, the NRC staff finds that the licensee's plan to train maintenance and operations personnel is consistent with NEI 12-02, 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 established and maintained for the testing, calibration, operation and abnormal response issues associated with the primary and backup spent fuel pool instrumentation channels.

In ISE RAI-12, the NRC staff requested 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 licensee was requested to include a brief description of the specific technical objectives to be achieved within each procedure.

During the onsite audit, and in the final compliance letter [Reference 44], the licensee provided a response to RAI-12, as follows:

> The modification review process will be used to ensure all necessary procedures are developed for maintaining and operating the spent fuel level instruments upon installation. These procedures will be developed in accordance with the FENOC procedural control process.
>
> The objectives of each procedural area are described below:
>
> Inspection, Calibration, and Testing - Guidance on the performance of periodic visual inspections, as well as calibration and testing, to ensure that each SFP channel is operating and indicating level within its design accuracy.

> Preventive Maintenance - Guidance on scheduling of, and performing, appropriate preventative maintenance activities necessary to maintain the instruments in a reliable condition.
>
> Maintenance - To specify troubleshooting and repair activities necessary to address system malfunctions.
>
> Programmatic controls - Guidance on actions to be taken if one or more channels is out of service.
>
> System Operations - To provide instructions for operation and use of the system by plant staff.
>
> Response to inadequate levels - Action to be taken on observations of levels below normal level will be addressed in site Off Normal procedures and/or FLEX [Diverse and Flexible Coping Strategies] Support Guidelines (FSGs).

In responding to the NRC staff question, the licensee's final compliance letter also provided a list of procedures identified to date. The NRC staff reviewed these procedures during the onsite audit and noted that they were developed using guidelines and vendor instructions to address the testing, calibration, maintenance, operation and abnormal response, in accordance with the provisions of NEI 12-02.

Based on the discussion above, the NRC staff finds that the licensee's proposed procedures are consistent with NEI 12-02, as endorsed by JLD-ISG-2012-03, and adequately address the requirements of the order.

4.3.3 Programmatic Controls: Testing and Calibration

In its OIP, the licensee stated that:

> Per NRC Order EA-12-051, processes will be established and maintained for Scheduling and implementing necessary testing and calibration of primary and Backup SFP level instrument channels in order to maintain the design accuracy.

In ISE RAI-13, the NRC staff requested the following:

- Further information describing 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. Include a description of plans to ensure necessary channel checks, functional tests, periodic calibration, and maintenance will be conducted for the level measurement system and its supporting equipment.

- A description of FENOC's procedure/process to implement the guidance in NEI 12-02 Section 4.3 on compensatory actions for one or both non-functioning channels.

- A description of the compensatory actions to be taken in the event that one of the instrument channels cannot be restored to functional status within 90 days.

In its compliance letter, the licensee provided a response, in which it stated that:

> SFP instrumentation channel/equipment maintenance/preventative maintenance and testing program requirements to ensure design and system readiness will be established in accordance with FENOC's processes and procedures. The design modification process will take into consideration the vendor recommendations to ensure that appropriate regular testing, channel checks, functional tests, periodic calibration, and maintenance is performed (and available for inspection and audit).
>
> Once the maintenance and testing program requirements for the SFP are determined, the requirements will be documented in maintenance program documents.
>
> Performance checks, described in the vendor operator's manual, and the applicable information will be contained in plant procedures. Operator performance tests will be performed periodically as recommended by the vendor.
>
> Channel functional tests with limits established in consideration of vendor equipment specifications will be performed at appropriate frequencies.
>
> Channel calibration tests per maintenance procedures with limits established in consideration of vendor equipment specifications are planned to be performed at frequencies established in consideration of vendor recommendations.
>
> Both primary and backup SFP instrumentation channels incorporate permanent installation (with no reliance on portable, post-event installation) of relatively simple and robust augmented quality equipment. Permanent installation coupled with stocking of adequate spare parts reasonably diminishes the likelihood that a single channel (and greatly diminishes the likelihood that both channels) is (are) out of service for an extended period of time. Planned compensatory actions for unlikely extended out-of-service events are summarized as follows:

# Channel(s) Out-of-Service	Required Restoration Action	Compensatory Action if Required Restoration Action not Completed Within Specified Time
1	Restore channel to functional status within 90 days (or if channel restoration not expected within 90 days, then proceed to Compensatory Action)	Immediately initiate action in accordance with Notes below
2	Initiate action within 24 hours to restore one channel to functional status and restore one channel to functional status within 72 hours	Immediately initiate action in accordance with Notes below

Notes:
1. Present a report to the on-site safety review committee within the following 14 days. The report shall outline the planned alternate method of monitoring, the cause of the non-functionality, and the plans and schedule for restoring the instrumentation channel(s) to functional status.
2. FENOC plans to place compensatory actions in NOP-LP-7300, FLEX Program for the Perry Nuclear Power Plant.

A Condition Report will be initiated and addressed through FENOC's Corrective Action Program. Provisions associated with out of service (OOS) or non-functional equipment, including allowed outage times and compensatory actions, will be consistent with 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.

In ISE RAI-14, the NRC staff requested the description of the in-situ calibration process at the SFP location that will result in the channel calibration being maintained at its design accuracy.

In its compliance letter, the licensee provided a response, in which it stated that:

The calibration verification involves attaching a sliding plate to the flat surface above the launch plate of the fixed bracket and placing a metal target against the probe cable above the water level. To complete this method, the water level must be a sufficient distance below the 100 percent level mark, which is nominally 12 inches below the launch plate. The differences in distances imparted by this standard can be physically determined and compared to the distance difference observed on the level display of the sensor electronics. The second portion of this calibration verification is a visual waveform check to verify proper signal operation. If the calibration verification check falls within the required calibration tolerance (±3 inches) and the waveform check meets the criteria outlined, the calibration verification is successful and the equipment may be returned to the normal operating setup. If an anomaly with the calibration is observed during this calibration verification, the electronic verification or calibration adjustment is to be followed for further investigation. This verification shall be performed on both channels (primary and backup) of the SFP instrumentation system independently.

NEI 12-02 contains provisions for the establishment of processes that will maintain the SFP level instruments at their design accuracy. It also contains provisions for the control of surveillances and out-of-service time for each channel. Based on the licensee's OIP, RAI responses, and compliance letter, the NRC staff finds that the licensee's proposed testing and calibration processes appear to be consistent with vendor recommendations and the provisions of NEI 12-02. Further, the licensee's proposed restoration actions and compensatory measures for the instrument channel(s) out of service meet the provisions of NEI 12-02.

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

4.4 Conclusions for Order EA-12-051

In its letter dated June 2, 2015 [Reference 44], the licensee stated that they would meet the requirements of Order EA-12-051 by following the guidelines of NEI 12-02, as endorsed by JLD-ISG-2012-03. In the evaluation above, the NRC staff finds that the licensee has conformed to the guidelines of NEI 12-02, as endorsed by JLD-ISG-2012-03. In addition, the NRC staff concludes that if the SFP level instrumentation is installed at PNPP 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 these two orders. The staff conducted an onsite audit at PNPP in December 2014 [Reference 18]. The licensee reached its final compliance date for Orders EA-12-049 and EA-12-051 on July 31, 2015, and April 18, 2015, respectively, and has declared that PNPP, Unit 1 is 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, will adequately address the requirements of Orders EA-12-049 and EA-12-051. The NRC will conduct an onsite inspection to verify that the licensee has implemented the strategies and installed the necessary equipment to demonstrate compliance with the orders.

6.0 REFERENCES

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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)

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10. Perry Nuclear Power Plant, Overall Integrated Plan in Response to 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), dated February 27, 2013 (ADAMS Accession No. ML13064A243)

11. Perry, Revision of Overall Integrated Plan for Perry Nuclear Power Plant in Response to 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), dated September 25, 2014 (ADAMS Accession No. ML14268A214)

12. Perry Nuclear Power Plant, First Six-Month Status Report in Response to 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), dated August 26, 2013 (ADAMS Accession No. ML13238A260)

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14. Perry Nuclear Power Plant, Third Six Month Status Report in Response to 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), dated August 28, 2014 (ADAMS Accession No. ML14240A285)

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16. 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)

17. Letter from Jeremy S. Bowen to Ernest J. Harkness dated January 22, 2014, regarding Perry Nuclear Power Plant Unit 1 – Interim Staff Evaluation Relating to Overall Integrated Plan in Response to Order EA-12-049 (Mitigating Strategies) (ADAMS Accession No. ML13338A460)

18. Letter from Peter Bamford to Ernest J. Harkness dated June 1, 2015, regarding Perry Nuclear Power Plant, Unit 1 – Report for the Audit Regarding Implementation of Mitigating Strategies and Reliable Spent Fuel Instrumentation Related to Orders EA-12-049 and EA-12-051 (ADAMS Accession No. ML15098A056)

19. Perry Nuclear Power Plant, Completion of Required Action by NRC Order EA-12-049, Order Modifying Licenses with Regard to Requirements for Mitigating Strategies for Beyond-Design-Basis External Events, dated August 20, 2015 (ADAMS Accession No. ML15232A594, non-public, a publically-available version is available at ADAMS Accession No. ML15362A497)

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

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

32. Letter from Nicholas Pappas (NEI) to Jack R. Davis (NRC) regarding FLEX equipment Maintenance and Testing Report dated October 3, 2013 (ADAMS Accession No. ML13276A573)

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44. FirstEnergy Nuclear Operating Company's (FENOC's), Completion of Required Action by NRC Order EA-12-051, Reliable Spent Fuel Pool Instrumentation, dated June 2, 2015 (ADAMS Accession No. ML15154B199)

45. Letter from Jason Paige (NRC) to Joseph Shea (Tennessee Valley Authority), dated August 18, 2014, regarding Watts Bar Nuclear Plant, Units 1 and 2 - Report For The Westinghouse Audit in Support of Reliable Spent Fuel Instrumentation Related To Order EA-12-051(ADAMS Accession No. ML14211A346)

46. Letter from Tekia V. Govan (NRC) to Ernest J. Harkness dated August 3, 2015, regarding Perry Nuclear Power Plant Unit 1 – Staff Assessment of Information Provided Pursuant to Title 10 of the *Code of Federal Regulations* Part 50, Section 50.54(f), Seismic Hazard Reevaluations for Recommendation 2.1 of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident (ADAMS Accession No. ML15208A034)

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49. Letter from William M. Dean (NRC) to Power Reactor Licensees dated October 27, 2015, Regarding Final Determination of Licensee Seismic Probabilistic Risk

Assessments Under the Request for Information Pursuant to Title 10 of the *Code of Federal Regulations* Part 50, Section 50.54(f), Regarding Recommendation 2.1 "Seismic" of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident (ADAMS Accession No. ML15194A015)

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58. FENOC letter to NRC, "Supplemental Information to Compliance with NRC Order EA-12-049," dated May 6, 2016 (ADAMS Accession No. ML16127A454)

Principal Contributors: M. Levine
J. Miller
K. Nguyen
P. Sahay
B. Titus
P. Bamford
D. Nelson

Date: May 16, 2016

FIP for Order EA-12-049. By letter dated May 6, 2016 (ADAMS Accession No. ML16127A454), FENOC submitted further supplemental information regarding the the FIP for Order EA-12-049.

By letter dated February 27, 2013 (ADAMS Accession No. ML13059A495), FENOC submitted it's OIP for PNPP in response to Order EA-12-051. At six month intervals following the submittal of the OIP, the licensee submitted reports on its progress in complying with Order EA-12-051. These reports were required by the order, and are listed in the attached safety evaluation. By letters dated November 6, 2013 (ADAMS Accession No. ML13340A653) and June 1, 2015 (ADAMS Accession No. ML15098A056), the NRC 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 June 2, 2015 (ADAMS Accession No. ML15154B199), FENOC submitted a compliance letter and FIP in response to Order EA-12-051. The compliance letter stated that the licensee had achieved full compliance with Order EA-12-051.

The enclosed safety evaluation provides the results of the NRC staff's review of FENOC's strategies for PNPP. The intent of the safety evaluation is to inform FENOC on whether or not its integrated plans, if implemented as described, will adequately address the requirements of Orders EA-12-049 and EA-12-051. The staff will evaluate implementation of the plans through inspection, using Temporary Instruction 191, "Implementation of Mitigation Strategies and Spent Fuel Pool Instrumentation Orders and Emergency Preparedness Communications/Staffing/ Multi-Unit Dose Assessment Plans" (ADAMS Accession No. ML14273A444). This inspection will be conducted in accordance with the NRC's inspection schedule for the plant.

If you have any questions, please contact Peter Bamford, Project Manager, Japan Lessons-Learned Orders Management Branch, at 301-415-2833, or at Peter.Bamford@nrc.gov.

Sincerely,
/RA/
Tony Brown, Acting Chief
Orders Management Branch
Japan Lessons-Learned Division
Office of Nuclear Reactor Regulation

Docket No.: 50-440
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NAME	PBamford	SLent	SBailey, w/comments*	OYee for JQuichocho, w/comments*
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OFFICE	NRR/JLD/JCBB/BC	NRR/JLD/JHMB	OGC	NRR/JLD/JOMB/BC(A)
NAME	CRoque-Cruz for JQuichocho, w/comments*	MShams, w/comments*	BHarris, NLO*	TBrown
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