NRC-004

July 7, 2016

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

In the Matter of	)	
	)	
DUKE ENERGY FLORIDA, LLC	)	Docket Nos. 52-029 and 52-030
	)	
(Levy Nuclear Plant, Units 1 and 2)	)	

NRC STAFF RESPONSES TO COMMISSION PRE-HEARING QUESTIONS

Pursuant to the Commission's "Order (Transmitting Pre-Hearing Questions)" of June 24, 2016, the staff of the U.S. Nuclear Regulatory Commission hereby responds to the questions posed in that Order. These questions generally pertain to subjects discussed in the staff's final safety evaluation report (SER)[1] or final environmental impact statement (FEIS).[2]

The Commission's Order directed some questions only to the staff, some questions only to Duke Energy Florida, LLC (the applicant), and some to both the staff and the applicant. The attachment to this filing presents the staff's responses.

/Signed (electronically) by/
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Dated at Jersey City, New Jersey,
this 7th day of July 2016

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[1] Final Safety Evaluation Report for the Levy Nuclear Plant Units 1 and 2 Combined License Application (May 31, 2016).

[2] NUREG-1941, Environmental Impact Statement for Combined Licenses (COLs) for Levy Nuclear Plant Units 1 and 2; Final Report (Apr. 2012).

ATTACHMENT
Staff Responses to Commission Pre-Hearing Questions

NRC STAFF RESPONSES TO COMMISSION PRE-HEARING QUESTIONS

1. **In its analysis of seismic seiches, the Safety Evaluation Report (SER) at 2-165 states: "Parameters for the maximum submarine landslide were determined for each of the provinces, except for the Campeche Escarpments where we are awaiting additional data."**

   New escarpment studies have recently been released (e.g., Monterey Bay Aquarium Research Institute, 2013) that map the escarpment in considerably more detail than studies that are reflected in SER Section 2.4. Did the Staff consider the more recent studies and their possible effect on the conclusions in the SER? If so what were the results?

   December 2013, American Geophysical Union Fall Meeting Presentation, Poster P41F-1985. December 12, 2013. Multibeam mapping of the Cretaceous-Paleogene meteorite impact deposits on the Campeche Escarpment, Yucatán, Mexico. Roberto Gwiazda (presenter); Charles K. Paull; David W. Caress; Mario Rebolledo-Vieyra; Jaime U. Fucugauchi; Iza Canales; Esther J. Sumner; Xavier Tubau Carbonell; Eve M. Lundsten; Krystle Anderson.

   Online: http://www.mbari.org/mapping-the-demise-of-the-dinosaurs-2/"

Staff Response: The Staff did not consider the more recent studies referenced in the question. However, the Staff is confident that results from the 2013 multibeam mapping of the Campeche Escarpment have no effect on the conclusions in the SER. This is because the Staff used a very conservative independent tsunami hazard analysis to verify the applicant's probable maximum tsunami results. Since the data needed to develop a realistic estimate of the landslide parameters for the Campeche Escarpment were not available, the Staff developed very conservative estimates of the maximum-potential submarine landslide for the Campeche Escarpment. Specifically, the Staff performed one-dimensional numerical model simulations using a provisional tsunami landslide source located at the Campeche Escarpment to estimate the resulting potential for flooding at the Levy Nuclear Plant (LNP) site. Initial conditions for the landslide source were based on maximum observed landslide parameters along the Florida Escarpment, which is a similar geologic environment. The Staff's analysis for the Campeche source computed the wave runup to stop after progressing 0.6 miles inland. Since the LNP site is 9.6 miles inland, the maximum extent of the tsunami wave does not come within 9 miles of the site.

Similar one-dimensional numerical model simulations were performed for all the potential tsunami sources for the LNP site (See Figure 1). The model simulations employed by the Staff were conservative because they did not account for the radial spreading of the wave and did not account for friction. This approach resulted in conservative estimates of the size and runup of the wave. These model simulations confirmed the applicant's conclusion that the Mississippi Canyon source has the greatest potential to bring the large tsunami wave to the Levy site and was appropriately designated as the probable maximum tsunami source.

The Staff then conducted independent confirmatory two-dimensional model simulations for the Mississippi Canyon. The Staff's tsunami model simulations employed modeling assumptions that included additional conservativisms not included in the applicant's model, such as assuming that the entire submarine landside volume 'slumps' instantaneously and into a large mass on the seafloor. The Staff's model produced results that showed the probable maximum tsunami estimated by the Staff (20 ft) or the applicant (12.94 ft) would not reach the LNP site (site grade of 51 ft).

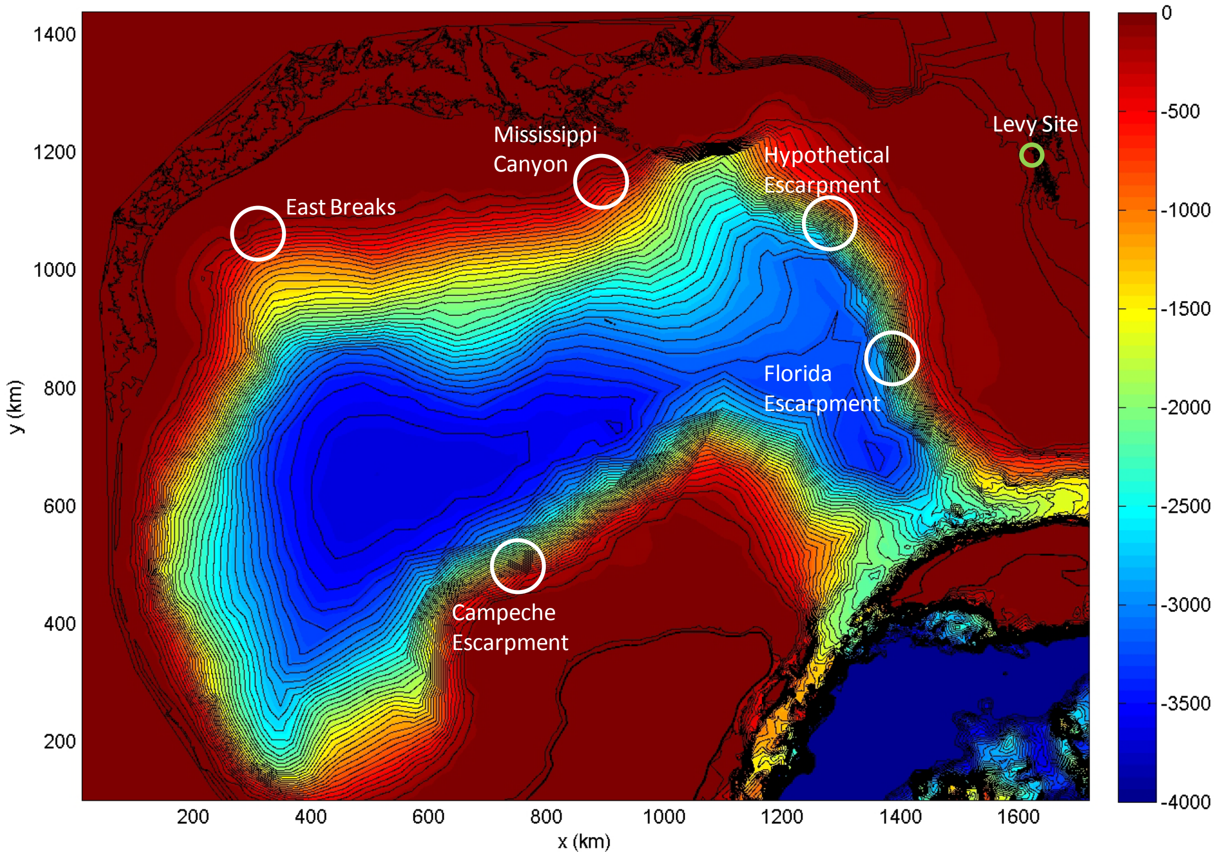

Figure 1. Bathymetry/topography contour surface of the Gulf of Mexico domain used for the tsunami hydrodynamic modeling. The general locations of the five potential tsunami sources (including the Campeche and Florida Escarpments) are shown by the white circles and the Levy County site is shown by the green circle. Bottom elevations are indicated by colors following the colorbar, with units in meters.

2. **In SER § 2.5.3.4.8, the Staff states that it "finds that the applicant provided a thorough and accurate description of the potential for tectonic and non-tectonic surface deformation at the site in support of the LNP COL application." This conclusion is based on the review of LNP FSAR Section 2.5.3.8 and other FSAR sections, "which document the lack of evidence for surface tectonic faulting and the possibility of non-tectonic surface deformation related to karst development at the site, as well as the examination by staff during the April and September 2009 site visits of core samples from the LNP site and examination of core logs, photographs, and descriptions in February 2010." However, the Staff is requiring the applicant to perform a final check for potentially detrimental tectonic and nontectonic geologic features in safety-related excavations at the LNP site through a geologic mapping license condition. Explain the need for this license condition and what would be the implications if potentially detrimental geologic features were found in the safety-related excavations.**

<u>Staff Response</u>: The geologic mapping license condition enables Staff to verify that site-specific geologic features observed in foundation grade level materials exposed in excavations for safety-related structures are appropriately documented. Title 10 of the *Code of Federal Regulations* (CFR), Section 100.23(d)(2) states that sufficient geologic data must be provided to clearly establish whether a potential exists for tectonic (i.e., due to faulting) and non-tectonic (e.g., due to dissolution) surface deformation. Regulatory Guide (RG) 1.132, "Site Investigations for Foundations of Nuclear Power Plants," indicates excavations for safety-related structures are important for verification of subsurface conditions and should be geologically mapped in detail after the excavations have been cleared to grade level to permit the characterization of geologic features in foundation materials. The finding in FSER Section 2.5.3.4.8 was based on the Staff's review of information submitted by the applicant, field observation of surficial geologic features, and examination of the results of subsurface investigations and tests (e.g., core and borehole logs, geophysical tests, and grout uptake tests). While these data are sufficient to support the Staff's safety findings, additional site-specific information on geologic features in foundation grade level materials is provided once the excavations for safety-related structures are completed and these materials are exposed. Implementation of the geologic mapping license condition would make any unforeseen geologic features in foundation grade level excavations available for Staff inspection. For example, the grouting program for controlling flow of groundwater into the excavations during construction would leave a visible record of sealed fractures and dissolution voids, if they existed, which would be included in the detailed geologic map of foundation grade level materials.

If potentially detrimental geologic features were found in foundation grade level excavations for safety-related structures, the applicant might be required to conduct additional site investigations in order to comply with the requirement in 10 CFR 100.23(d)(2). These potential investigations would either ensure that the features do not represent a geologic hazard at the proposed site or assess the need for potential changes in the design for the proposed facility.

3. The Subsection 2.5.4.4.3.7, "Grouting of Karst Features," of the SER articulates that the purpose of the grouting program is to create a semi-impermeable barrier to reduce ground water inflow into the excavation, thereby reducing dewatering requirements during construction. The program will grout the eroded vertical joint sets and bedding planes through primary, secondary and if necessary through tertiary grouting to achieve the desired seepage cutoff. As noted in the subsection, the Staff has accepted that that the foundation system is designed to accommodate isolated voids up to 10 ft. in size, which is at least double the conservatively estimated lateral dimension of any actual void intercepted. Finally, the Staff acknowledges that the grout program is not intended to strengthen the foundation, but only reduce inflow into the excavation during construction. Filling of all the voids is therefore not required for stability. However, the Staff concludes, the proposed grouting in combination with the diaphragm wall, and the 35-foot Roller Compacted Concrete (RCC) bridging mat will improve the nuclear island basemat/foundation conditions.

What inspections, tests, and acceptance criteria will the applicant use to demonstrate that:

1. **the grouted rock will perform its intended function over the life of the plant; and requirements?**

2. **potential sinkholes in the rock will be filled with grout to minimize the inflow of water over the life of the plant?**

If none, why are they not necessary?

Staff Response: The Staff does not view inspections, tests, analyses, and acceptance criteria (ITAAC) as necessary to demonstrate grouting performance during the lifetime of the proposed plant. The proposed grout program only reduces potential groundwater inflow during excavation and construction and is not intended to function over the life of the plant. However, the proposed 75-ft thick grouted zone in the Avon Park Formation will significantly reduce porosity and permeability and limit the ability of groundwater to infiltrate into the Avon Park Formation during excavation and construction. Success of the grout program will be determined by the lack of groundwater intrusion during the excavation dewatering program. While the proposed grouting is not safety-related, it will be performed using accepted industry quality standards for grouting.

Although the filling of voids with grout should increase the strength of the Avon Park Formation, this potential strengthening was not credited in the foundation analyses. The Staff reviewed the applicant's foundation analyses and confirmed that bearing capacity, settlement, and site response were assessed on the basis of properties of the Avon Park Formation as measured during the site characterization program, without any credit for grouting. Consequently, the applicant's safety case does not depend on the post-construction performance of the grouted zone.

The Staff confirmed results of the applicant's site characterization related to dissolution voids by examination of rock outcrops, borehole lithologic and geophysical logs, and core samples, as well as independent review of significant publications cited in the FSAR. In addition, during a site audit the Staff observed a grout-filled fracture in a core sample obtained after grout testing was performed and examined the grout uptake test data. The Staff concluded that the foundation system for accommodating isolated voids up to 10 feet in diameter was sufficiently conservative and supported by the site investigation results.

The Staff also determined that dissolution rates in the Avon Park Formation were sufficiently low, such that potential increases in subsurface void size would not be significant. To evaluate dissolution, the applicant cited the Crystal River 3 FSAR, which shows that the Ocala Limestone (present at the Crystal River site) is dissolving at a rate of 1×10^{-4} percent per year, or 6×10^{-3} percent over 60 years. Due to high levels of dolomitization with recrystallization in the Avon Park Formation compared to the Ocala Limestone and the less soluble nature of dolomite compared to limestone, the Avon Park Formation is less susceptible to dissolution and consequential development of karst features than the Ocala Limestone. The Staff concluded that these dissolution rates would not significantly affect the size of the maximum postulated void (i.e., 10 ft in diameter) used in the foundation analysis. In addition, the 75-ft grouted section will also reduce the potential for future dissolution by restricting water infiltration pathways, but this benefit is not credited in the Staff's assessment.

In summary, the Staff's safety conclusion on the stability of subsurface materials and foundations does not rely on the presence of grouting. Specifically, the Staff's safety conclusion does not depend on the grouted rock restricting water infiltration over the life of the plant or grouting for enhancing the structural integrity of foundation materials over the life of the plant. The purpose of grouting is for restricting water infiltration during construction, as part of the foundation dewatering program, and is not safety-related. The Staff concluded that the size of postulated voids used in the foundation analyses and design is sufficiently conservative for the life of the plant, without taking credit for the presence or absence of grouted materials. Therefore, no ITAAC are required to demonstrate grouting performance during the lifetime of the proposed plant.

4. The uniqueness of the RCC bridging mat and grouted subgrade below the nuclear island has prompted the applicant (as presented in a slide to the Advisory Committee on Reactor Safeguards Subcommittee meeting of October 18, 2011) to consider a long-term monitoring program of the foundation system. Given the importance of the RCC bridging mat, as a Category I Structure, should the plant technical specifications include a condition/performance monitoring program with applicable surveillance and limiting condition for operation requirements?

Staff Response: In FSAR Section 3.8.5, "Foundation," the applicant identified the RCC bridging mat as a structure that was subject to 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." In Section 2.5.4.10.3.5, "Subsurface Instrumentation," of the FSAR, the applicant provided detailed information regarding its settlement monitoring program. The applicant stated it will develop the detailed settlement monitoring program prior to construction. The settlement of the nuclear island (NI) foundation, along with the adjacent structures, is expected to be small. Table 2.0-201, "Comparison of AP1000 DCD Site Parameters and LNP Site Characteristics," (Sheet 6 of 9) shows the projected settlements of the LNP site to be significantly lower than (i.e., bounded by) the acceptable values of the AP1000 DCD. The applicant intends to install settlement bench marks to measure the differential settlement between the NI and the adjacent buildings during and after construction. A monitoring program will also be implemented after construction to monitor any long-term settlement. While long-term settlement is expected to be minimal, the settlement bench marks installed during the construction phase will be used post-construction to monitor settlement of the NI structures. The applicant's settlement monitoring program is consistent with the requirements of 10 CFR 50.65, and the guidance in RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Therefore, it is not necessary to include a condition/performance monitoring program within the technical specifications.

5. Alkali-carbonate reaction is observed in certain Dolomitic rocks. Dolomitic limestone may include up to 50% dolomite. As noted during the supplemental borings, the collected specimens indicated that the noted voids were filled with fragmented rock. Since grouting is expected to reduce the porosity and voids of the underlying rock, it is possible that during the process, the Calcium Hydroxide ($Ca(OH)_2$) or Portlandite of the grout cement may react with the fragmented Dolomite ($CaMg(CO_3)_2$). The reaction (dedolomitization) and subsequent potential recrystallization to Brucite ($Mg(OH)_2$) may cause considerable expansion.

Has the applicant looked at the potential for alkalicarbonate reaction? If so, has the applicant performed any petrographic examination of the recovered subsurface rock (especially those containing dolomite) to examine whether the findings would be a cause for concern during the grouting process?

Response to be submitted by the applicant only.

6. The applicant plans to use a sheet-type waterproofing system for the below grade exterior walls exposed to flood and groundwater under seismic Category I structures. Section 3.4.1.1.1 of the AP1000 design control document (DCD) states:

> **The COL applicant will use a waterproofing system for foundation mat (mudmat) and the below grade exterior walls exposed to flood and groundwater that will demonstrate a friction coefficient ≥ 0.55 with all horizontal concrete surfaces. This friction coefficient is maintained for the life expectancy of the plant and will not introduce a horizontal slip plane increasing the potential for movement during an earthquake. . . . The waterproof function of the membrane is not safety related; however, the membrane between the mudmats must provide adequate shear strength to transfer horizontal shear forces due to seismic (SSE) loading. This function is seismic Category I.**

Section 3.8.5.4, "Technical Evaluation," of the SER states:

> **In a letter dated September 23, 2010, the LNP applicant proposed identifying, as LNP COL 2.5-17, the information in Section 3.8.5.1 addressing the type of waterproofing system to be used for the below grade exterior walls exposed to flood, and groundwater under seismic Category I structures. The applicant provided a waterproofing material to be used for the below grade, exterior walls exposed to flood and groundwater under seismic Category I structures. The applicant stated that a sheet type waterproofing membrane will be used for both the horizontal and vertical surfaces under Seismic Category I structures. The performance requirements to be met by the COL applicant for the waterproofing material are described in Section 3.4.1.1.1.1 of the AP1000 DCD. Thus, the NRC Staff considers LNP COL 2.5-17 to be resolved.**

The applicant has selected a waterproofing membrane to support the functions of the nuclear island during the life of the plant. The applicant defined the waterproof function of the membrane to be nonsafety related. Its sliding, however, was defined as safety related. Its failure to function as a watertight barrier could impact the performance of the nuclear island basemat.

1. **For the applicant: Explain how the consequences of potential damage, anticipated aging, and creep were factored in when selecting and qualifying the membrane as a watertight barrier. For the Staff: how were these effects evaluated in the Staff's review?**

2. **Is Table 3.8-3, "Waterproof Membrane, ITAAC," sufficient to demonstrate that its safety and non-safety functions will be maintained for the life of the plant? Is a license condition appropriate to ensure these functions?**

Staff Response:

1. During the AP1000 DCD review, the Staff reviewed Westinghouse response to request for information (RAI) TR85-SEB1-35 which indicated that the waterproofing system for

the below grade walls and mud mat would consist of either the High Density Polyethylene (HDPE) double-sided textured membrane; HDPE single-sided adhering sheet membrane; self-adhesive, rubberized asphalt/polyethylene membrane (for walls only); or sprayed-on waterproofing membrane based on polymer-modified asphalt or polyurea. In addition, the industry standards used to specify performance requirements and other design requirements (e.g., maximum crack width) for the waterproofing systems were provided. The waterproofing materials and performance requirements provided were found to be acceptable based on the use of the applicable industry standards and practices.

The LNP applicant will use a waterproofing system for its foundation mat and the below grade exterior walls that is consistent with the waterproofing criteria described in Section 3.4.1.1.1.1 of the AP1000 DCD. The waterproofing material selected will be qualified by test, with commercial grade dedication and lab testing to achieve a minimum coefficient of friction of 0.55. This friction coefficient is maintained for the life expectancy of the plant and will not introduce a horizontal slip plane that would increase the potential for movement during an earthquake.

2. The safety function of the waterproofing membrane (to prevent sliding of the NI) addressed in Table 3.8-3 is sufficient to demonstrate that its safety and nonsafety functions will be maintained for the life of the plant with a friction coefficient equal to or greater than 0.55 against sliding. The Staff reviewed the soil structure interaction analysis for the LNP application and concluded that the NI is stable against sliding. The nonsafety function of the waterproofing membrane is to prevent water intrusion from ground water and flooding for the exterior walls and below grade of the safety related structures. The Staff does not typically impose license conditions or ITAAC to address nonsafety functions. The ITAAC will ensure that the safety function of resisting sliding is demonstrated through material qualification testing. The Staff does not view a license condition that would monitor the condition of the membrane through the life of the plant as appropriate because this material is not expected to degrade over the expected life of the plant and, once installed, monitoring is not feasible. The waterproofing material selected will be qualified by test, with commercial grade dedication and lab testing to achieve a minimum coefficient of friction of 0.55. As stated in the DCD, this friction coefficient is maintained for the life expectancy of the plant and will not introduce a horizontal slip plane that would increase the potential for movement during an earthquake. Therefore, the ITAAC is sufficient.

7. Given that the grouting program will diminish but not eliminate ground water infiltration, proper compaction of the Roller Compacted Concrete (RCC) bridging mat layers during construction is of utmost importance.

The LNP will use unreinforced RCC placed in layers as a bridging mat over karst. Karst geological features include limestone and dolomite rocks that would still be exposed to the existing ground water. Additional rainwater seeping into nearby surface joints and could adversely affect unmitigated underlying carbonate rocks. This could lead over the life of the plant to additional geologic discontinuities (e.g., caverns, sinkholes) and less than desirable future substrate environments that could affect the performance of RCC bridging mat. The importance of proper and adequate compaction is captured in American Concrete Institute standard ACI 309.5R-00, which states:

As the water content increases from the optimum level, the workability increases until the mixture will no longer support the mass of a vibrating roller. As the water content decreases from the optimum level, sufficient paste is no longer available to fill voids and lubricate the particles, and compacted density is reduced.

How will the applicant control the consistency of the in situ compaction of individual lifts of the RCC bridging mat to be optimal, so that potential seepage paths and poorly bonded lifts are eliminated?

Staff Response: In FSAR Section 3.8.5.11.1, the applicant committed to follow industry codes and standards which provide methods for controlling the consistency of the in situ compaction of individual lifts of the RCC bridging mat, in order to eliminate the potential seepage paths and poorly bonded lifts. Seepage can be controlled through appropriate design and construction procedures. This commitment included using the RCC guidance and construction standard practices described in the U.S. Army Corps of Engineers (USACE) Engineering Manual 1110-2-2006, "Roller Compacted Concrete." Section 5-3, "Seepage Considerations," of the USACE engineering manual describes procedures to properly proportion, mix, place, and compact the RCC for making it as watertight a structure as conventional concrete for controlling seepage.

Additionally, the applicant is committed to constructing a test pad with the specified RCC and bedding mixes. The test pad construction will use mixing, placement, and compaction procedures and equipment comparable to those that will be used during the LNP RCC bridging mat construction. Pursuant to License Condition 2.D(12)(g), the applicant is required to make available to the NRC, 180 days prior to construction, the 90-day test report for the Strength Verification and Constructability Testing Program for this test pad.

8. The applicant states that lateral stiffness of the drilled shaft is governed by the soil properties in the top 10 to 16 feet. However, Figure 3.7-226 of the FSAR shows that some of the drilled shafts are located almost adjacent to the nuclear island diaphragm wall (minimum distance of 1 foot).

Both the applicant and the Staff considered the implications of lateral movements and interactions between the nuclear island structures, the adjacent structures, and their foundations, concluding that the provided seismic gap is adequate to minimize any potential interactions between buildings. In addition, the applicant states in the FSAR that the top of the diaphragm wall and the controlled low strength material fill between the diaphragm wall and the NI wall are below the individual building mat foundations and therefore there are no concerns of damage or interaction. There is no discussion, however, as to the effects of lateral movement of the annex, turbine, and radwaste building mats or drilled shafts on the engineered fill. Proper compactness of the engineered fill at all times ensures its design strength, compressibility, and permeability will be maintained ensuring compliance for its intended function.

1. **Were the effects of lateral loads from drilled shafts on the engineered fill, if any, considered in the applicant's evaluation or the Staff's review?**

2. **Following a seismic event, what measures, if any, will be taken or required to ensure continued compliance of engineered fill to specifications?**

<u>Staff Response</u>:

1. The Staff review did not specifically call out the effects of lateral loads from drill shafts on engineered fill, but this was not necessary for the Staff to make its safety findings. The engineered fill below the annex, turbine, and radwaste buildings is not safety-related and does not extend to the area beneath the NI. The area beneath the NI is isolated from any lateral load effects from drilled shafts by a diaphragm wall. However, the applicant intends to use controlled engineered fill beneath the nonsafety-related structures, which will provide lateral support to the drilled shafts that support those structures. The Staff evaluated the applicant's computed probable maximum relative displacement during a safe shutdown earthquake between the NI and the adjacent building foundations, considering the lateral effects of the drilled shaft foundations. The probable maximum relative displacement obtained was less than 1 inch. The probable maximum relative displacement calculation included the drilled shaft supported foundation mat displacements including the drilled-shaft-to-drilled-shaft interaction effects, additional displacements due to soil column displacement, and the NI displacement at design grade. This was an indirect evaluation of the ability of the engineered fill to provide lateral support to the drill shafts. Therefore, the scope of the Staff's evaluation was conservative.

2. The Staff is not aware of any specific measures that the applicant might take to assess the impact of a seismic event on engineered fill beneath non safety-related structures. The top of the diaphragm wall and the controlled low strength material fill between the diaphragm wall and the NI wall is at least 5 feet below the nonsafety-related structures foundation mat. The engineered fill will be compacted to 95 percent of its maximum dry density as determined by ASTM D 1557, Modified Proctor method, with a dry unit weight of 110 pounds per cubic feet. The moisture content of the engineered fill will be controlled to within plus or minus 2 percent of its optimum moisture. Proper compactness of the engineered fill at all times ensures its design strength, compressibility, and permeability will be maintained ensuring compliance for its intended function. Engineered fill is used from the top of the controlled low strength material fill to the bottom of the nonsafety-related structures foundation. This interface is designed to avoid hard contact between the NI and the nonsafety-related structures foundation resulting from the relative displacements during the seismic event. Thus, no seismic interaction is expected between the NI and nonsafety-related structures. Therefore, the Staff expects that there would be no effect on the fill from a seismic event and believes no post-event inspection would be necessary.

9. LNP COL 2.5-13 states:

> **Settlement bench marks will be installed within the subgrade mudmat . . . and monitored before and periodically during construction of the nuclear island basemat and sidewalls prior to placement of backfill materials. Additional bench marks will be installed approximately 1 m (3 ft.) above site grade . . . and connected to the sidewalls of the nuclear island, directly above the deeper benchmark locations described previously. These bench marks will be monitored during backfilling operations and, periodically, during and after construction of the nuclear island structures.**

Since the RCC is classified as a seismic Category I, safety-related structure, how would the applicant monitor RCC bridging mat deformations beyond those induced from settlements (e.g., material reactivity based, DEF, etc.)?

Response to be submitted by the applicant only.

10. A proposed ITAAC in Table 3.8-2 states that, "during construction, inspection of the physical properties of the rock socket for each drilled shaft will be performed in accordance with LNP Inspection of the as-built drilled shaft foundation physical arrangement will also be performed." The acceptance criterion for the ITAAC is that a "report exists that reconciles the during construction physical properties of the rock socket for each drilled shaft and the as-built physical arrangement of the Turbine, Radwaste, and Annex Buildings' drilled shaft foundations with design specifications and drawings. The report concludes that the as-built drilled shaft foundation conforms to the design commitment." It is not clear how the applicant will confirm load carrying capacity of the drilled shafts. The karst rock may have voids below the rock socket for drilled shafts.

The applicant provides explanation in the FSAR on how the design and installation of the drilled shafts would be implemented. The SER does not appear to address LNP SUP 3.8-2.

1. **Please further explain why the proposed construction methodology in LNP FSAR 3.8.5.9, "Drilled Shaft Foundations Design and Installation" is acceptable.**

2. **How would the performance of the shafts be verified?**

<u>Staff Response</u>:

1. The SER evaluates the design of Category I structures. Category I structures have a safety function. The Turbine, Radwaste, and Annex buildings are non-Category I structures.

   However, in the SER the potential of a non-Category I structure to adversely impact the safety function of a Category I structure is evaluated. In SER Sections 3.7 and 3.8 the Staff evaluated the interaction between Category I and the non-Category I structures for the Levy site and concluded that the seismically induced displacements are significantly smaller than the seismic gap provided by the AP1000 DCD. Thus, the Staff did not need to document in the SER its evaluation of the construction methodology for the "Drilled Shaft Foundations Design and Installation"

2. The performance of the foundation system for the non-Category I structures as used in the evaluation of the interaction analysis is assured by the ITAAC presented in Table 3.8-2, "Drilled Shaft Foundation ITAAC," which is to preclude movement so as not to exceed the separation provided between the Category I and the non-Category I structures. No additional performance verifications are needed.

11. **Recent modifications to the reactor pressure vessel internals indicate the addition of a flow skirt to the vessel bottom head. In addition, neutron panels have also been added. Additions and vessel modifications invariably also involve added bolted or welded connections. A perennial problem in vessel internals has been irradiation-enhanced stress relaxation, creep, and swelling which could result in dimensional instabilities, loss of preload (i.e., loosening of bolts), fasteners, keyed and/or pinned connections resulting possibly in increased vibrations and further deterioration of the connections.**

    How has the applicant demonstrated that the fasteners of the added flow skirt and neutron panels can be maintained through the expected life of the facility?

Staff Response: The design of the reactor pressure vessel internals, including the flow skirt and neutron panels, was certified by the Commission on December 30, 2011. The Staff review of this design is contained in the FSER of the AP1000 Standard Plant Design (NUREG-1793 and its supplements).

The AP1000 reactor pressure vessel internal components are designed to meet the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section III, Subsection NG limits to ensure the structural integrity throughout the life of the plant. The flow skirt is welded to support lugs on the reactor vessel bottom head below the core support plate, and the flow skirt-to-support lug welds are designed to ASME B&PV Section III, Subsection NB. The neutron panels are attached to the outside of the core barrel with threaded fasteners. The neutron panels have been sized to prevent excessive thermal loading on the bolts and to withstand flow, thermal, and vibratory loading. In addition, the bolts and preload of the bolts have been sized to accommodate radiation relaxation and radiation-induced gamma heating such that the preload is maintained. Westinghouse also performed a flow-induced vibration analysis on the neutron panels and flow skirt according to RG 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals during Preoperational and Initial Startup Testing," to prevent high cycle fatigue. The first AP1000 plant (Vogtle or Summer) will perform reactor internals preoperational vibration testing to confirm the stress calculations that the reactor internal components will maintain their structural integrity during normal operation and transient conditions. Subsequent AP1000 plants (including LNP) will also perform preoperational testing to confirm the structural integrity of the reactor internal components. Further discussion of this topic can be found in Sections 3.9.2 and 3.9.5 of NUREG-1793, Supplement 2.

To comply with 10 CFR 50.55a, the LNP applicant would be required to follow the ASME Code, Section XI, Table IWB-2500-1, which specifies visual examination requirements for the in-service inspection of some reactor vessel internal components. In addition, the Staff uses implementation of Electric Power Research Institute Report MRP-227-A, "Pressurized Water Reactor Internals Inspection and Evaluation Guidelines" (ADAMS Accession No. ML120170453) to provide oversight as a living program for materials degradation issues in reactor internals, and it is the Staff position that use of MRP-227-A will provide adequate assurance of quality and safety. Through their commitment to NEI 03-08, "Guideline for the Management of Materials Issues" (ADAMS Accession No. ML101050337), operating U.S. commercial pressurized water reactors implement the Mandatory and Needed elements of MRP-227-A. Should LNP be constructed and placed into operation by the applicant, the licensee would be expected to implement the Mandatory and Needed elements of MRP-227-A, as appropriate.

The basis of MRP-227-A addresses all operating reactor internals designs, some of which contain flow skirts and neutron panels. Although neither component was screened in as a primary component for inspection due to an evaluated low probability and consequence of component failure, should adverse levels of degradation be evident based on the inspection results from other internals components affected by similar degradation mechanisms, the Staff would require action to be taken through the Materials Reliability Program to evaluate such operating experience and revise MRP-227-A, if needed, to further address inspection of the flow skirt and neutron panel components.

12. As stated on page 8-19 of the SER, the Staff relied on the request for additional information (RAI) responses in letter dated March 21, 2014 (ADAMS Accession No. ML14010A421) (Response to RAI 114), to conclude that the supplemental information provided by the applicant to address the open phase condition of the offsite electric power system, as described in Bulletin 2012-01, "Design Vulnerability in Electric Power System" (ML12074A115), is acceptable. The Staff stated that the Final Safety Analysis Report (FSAR) and the ITAAC supplemental texts included in the SER are those provided in the RAI responses. However, the ITAAC texts in the SER (page 8-24) differ from the ITAAC texts in the RAI responses (Response to RAI 114, at 16).

Explain how the ITAAC texts changed from the version contained in the RAI responses to the version in the SER.

Staff Response: The above question and the SER correctly identify the proper reference for the applicant's response (March 21, 2014); however, the documents cite an incorrect ADAMS accession number (ADAMS Accession No. ML14010A421 from above). The ADAMS number referred to in the SER is the January 9, 2014, response. The correct ADAMS accession number for the March 21, 2014, response is ML14086A656. The Staff has verified the contents of this reference and confirmed that the ITAAC text stated in the response is the same as that stated in the SER (page 8-24).

13. Page 8-19 of the SER sets forth the Staff's position for an acceptable approach for passive designs to address the open phase condition, which includes four elements. The first element is a dedicated automatic detection of one and two open phase conditions of the offsite power system with and without a high impedance ground fault condition on the high voltage (HV) side of the main power transformer under all loading and operating configurations.

The supplemental text to the FSAR states:

> **"The system <u>detects</u> an open phase condition (with or without a concurrent high impedance ground on the HV side of the transformer) on one or more phases under all transformer loading conditions." The supplemental text for the ITAAC in the SER states: "The credited GDC [General Design Criterion] 17 offsite power source is monitored by an open phase condition monitoring system that <u>can detect</u> the following at the HV terminals of the transformer connecting to the offsite source, over the full range of transformer loading from no load to full load: (1) loss of one of the three**

phases of the offsite power source (with or without a high impedance ground fault condition), or (2) loss of two of the three phases of the offsite power source (with or without a high impedance ground fault condition).”

Confirm that the open phase monitoring system will <u>automatically detect</u> one or two open phase conditions (with or without a high impedance ground fault condition) at the HV side of the main power transformer under all electrical system configurations and loading conditions.

<u>Staff Response</u>: In the response dated March 21, 2014 (ADAMS Accession No. ML14086A656) and in Section 8.2.4 of the SER (under LNP SUP 8.2-5), the applicant stated that “the monitoring system is installed on the credited GDC 17 offsite power circuit that provides **continuous** open phase condition monitoring.” [Emphasis added.] In addition, the applicant states that “the system design utilizes commercially available components including state of the art digital relaying equipment and input parameters as required to provide loss of phase detection and alarm capability. The Staff repeats this information in the SER on page 8-20. Since the system is continuously monitoring for open phase conditions using digital relays, the Staff concluded that the monitoring system automatically detects an open phase for either of the one or two open phase conditions (i.e. continuous monitoring meets the Staff position of automatic detection). Therefore, if an open-phase event should occur, it will be automatically detected and alarmed in the control room.

14. The second element of the Staff’s position is an alarm in the control room, which activates upon detection of an open-phase condition, for operators to take manual actions if the standby diesel generators are not automatically connected to the auxiliary alternating current buses (ES-1 and ES-2).

The supplemental text to the FSAR states: “The open phase condition monitoring system provides an alarm to the operators in the control room should an open phase condition occur on <u>the high voltage source to the main step-up transformers.</u> [….] Operator actions and maintenance and testing activities are addressed in procedures […] Plant operating procedures, including off-normal operating procedures associated with the monitoring system will be developed prior to fuel load.”

1. **Confirm that the plant procedures will specify operator actions for connecting the standby diesel generators to the ES-1 and ES-2 buses if they are not automatically connected.**

2. **Explain why the applicant was not required to include in the FSAR that operators will take manual actions if the standby diesel generators are not automatically connected to the ES-1 and ES-2 buses.**

Clarify what the “high voltage source to the main step up transformers” is.

<u>Staff Response</u>:

1. While the FSAR describes these procedures as including operator actions, as stated below, the FSAR does not specify such actions in detail in regard to open phase

conditions, nor did the Staff review the details of the procedures for operator actions, which are not yet available.

In its FSAR, the applicant stated that the monitoring system would provide an alarm to the operators should an open phase condition occur.

The Staff position is that such an alarm is necessary, but the specific actions to be taken will depend on plant and grid conditions at the time of the event.

SER Section 13.5, "Plant Procedures," states that, "Descriptions of the administrative and operating procedures that the applicant uses to ensure routine operating, off-normal, and emergency activities are conducted in a safe manner are provided. The applicant, in its plant procedures, provided a brief description of the nature and content of the procedures…."

SER Section 13.5.6 concludes, "The NRC staff reviewed the application and checked the referenced DCD. The NRC staff's review confirmed that the applicant addressed the required information relating to plant procedures, and there is no outstanding information expected to be addressed in the LNP COL FSAR related to this section."

Thus, the Staff recognizes that procedures will be developed to include operator actions (as stated in the SER) to meet the Staff position for detection and alarm of open phase conditions. SER Section 13.5 states that the Staff has reasonable assurance that the administrative procedures will be established to provide licensed operators and non-licensed plant staff with sufficient knowledge and operating experience to start up, operate, and maintain the plant in a safe manner.

2. The Staff's safety finding is based on the monitoring system and alarm (whose function is substantiated by the ITAAC) which will alert the operator to take appropriate actions for which he has been trained and has procedures to follow. The safety finding is not based on the content of the procedures.

   Connecting the nonsafety standby diesel generators is an example of a potential operator action. However, the Staff anticipates that in most circumstances the licensee will be able to switch to an alternate offsite power source.

   Moreover, in the AP1000 design, ac power systems are not required for accident mitigation (as stated in AP1000 DCD Tier 2 Section 8.1.4.2.2). As such, the information included in the FSAR regarding operator actions is adequate to meet the Staff position of detection and alarm of open phase conditions, and the detailed description for connection of two nonsafety ancillary diesel generators was not necessary for the Staff's conclusion to ensure compliance with GDC 17.

   As explained above, the applicant is required to have associated procedures and training in place prior to the Commission making a finding that acceptance criteria of ITAAC have been met, as required under 10 CFR 52.103(g). The operator will need to follow the procedure which may include manual actions.

   The high voltage source to the main step-up transformers is the 500 kV switchyard, which has several incoming transmission lines feeding the switchyard and several circuits from the switchyard to the plant. This is shown in FSAR Figure 8.2-201, “Off-site Power System One-Line Diagram LNP 1 and LNP 2.”

15. 10 C.F.R. Part 50, Appendix E, § I.3, footnote 1 requires a plume exposure pathway emergency planning zone (EPZ) that consists of an area about 10 miles in radius. The regulation also provides that the actual size and shape of the EPZ will vary depending on demography, topography, land characteristics, access routes, and jurisdictional boundaries. Figure Intro-3 of the emergency plan shows the Levy Nuclear Plant (LNP) EPZ to be consistent with these requirements, with the apparent exception of an area on the southeast side of the EPZ within Citrus Springs. The defined EPZ boundary has about a 1.5- to 2-mile reduction in the EPZ periphery in this area. A review using a satellite view in Google Maps and StreetView shows that this excluded area contains residences.

1. **How many people reside in this excluded area?**
2. **Why was the current boundary selected, given the existence of roads not far outside of the 10-mile radius that could have been used as a boundary for this area?**

Additional reference: 44 Fed. Reg. 61,123 (Oct. 23, 1979).

<u>Staff Response</u>:

1. The Staff conservatively estimates that 3,700 people live in the northwest area of Citrus Springs, Florida, which is within the arc of the 10 mile ring drawn from the LNP site, but not included in the EPZ.

2. The size and configuration of the 10-mile plume exposure pathway EPZ for the LNP was discussed and coordinated with representatives from the State of Florida Division of Emergency Management (DEM) and the Levy, Citrus, and Marion County Emergency Management Directors from the 10-mile EPZ risk counties. Demographical data, topographical information, land characteristics, access routes, and jurisdictional boundaries were all taken into consideration in the determination of the 10-mile EPZ boundary.

   The design and configuration of the 10-mile plume exposure pathway EPZ and associated Protective Action Zones (PAZ) were discussed by the applicant with State and county emergency management personnel at a meeting on February 14, 2007. Another meeting was held on June 19, 2007, between the applicant, State DEM, and county emergency management directors, at which the EPZ and PAZ boundaries were finalized.

   The boundaries were developed along well-defined features (major roadways for the most part) that would be easily identifiable to area residents and that would conform to an EPZ radius of about 10 miles. These boundaries were developed in conjunction with the offsite agencies. As such, the Staff concluded that the applicant appropriately coordinated the identification of the 10-mile plume exposure pathway EPZ boundary with State and county emergency management personnel consistent with NRC guidance found in NUREG-0654/FEMA- REP-1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants."

16. LNP Technical Specification 16.1 for the Containment Leakage Rate Testing Program states:

> **A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program, dated September 1995," as modified by approved exceptions.**

Does the applicant intend to exempt certain containment pressure boundary components from leak rate testing? If so, which components?

<u>Staff Response</u>: The language in LNP FSAR Section 16.1, Technical Specification 5.5.8, is standard language for the AP1000 Design Control Document and all of the AP1000 combined license applications. Since the LNP combined license application incorporates by reference the AP1000 standard design, the application also incorporates the two exceptions to RG 1.163 that the Staff approved in the AP1000 standard design. These two exceptions can be found in

NUREG-1431, "Standard Technical Specifications – Westinghouse Plants." The applicant has not communicated to the Staff any intention to request an exemption related to the Containment Leakage Rate Testing Program.

17. Section B.5.1 of the LNP emergency plan states that there is a technical support center (TSC) and operational support center (OSC) for each unit. It also specifies that in the event of a site-wide emergency (e.g., security event or natural phenomenon) Unit 1 will take the lead and that only the TSC and OSC of the lead unit will be activated.

1. **Would the lead stay with Unit 1 if the event resulted in a substantial challenge to the fission product barriers at Unit 2?**

2. **Would the onsite response continue to be implemented from one of the TSCs/OSCs or would both TSCs and OSCs be staffed and activated to respond to the event in the respective units?**

Staff Response:

1. In the event of an emergency, the Shift Manager initially assumes the role of Emergency Coordinator, with the Plant Manager (or designated alternative) relieving the Shift Manager of Emergency Coordinator duties. The emergency plan states that for a site-wide emergency affecting both the units, Unit 1 will take the lead having overall command and control for responding to the event. The Staff considers the actions and considerations necessary to evaluate and make a determination as to whether the Unit 1 and/or Unit 2 TSC and OSC should be activated, and which should be the lead unit as a result of a declared emergency, to be within the discretion of the Emergency Coordinator at the time of the event.

2. The emergency plan provides that the Emergency Coordinator is responsible for the direction of all emergency response activities on site during an emergency. As stated above, the Staff considers the actions and considerations necessary to evaluate and make a determination as to whether the Unit 1 and/or Unit 2 TSC and OSC should be activated, and which should be the lead unit as a result of a declared emergency, to be within the discretion of the Emergency Coordinator at the time of the event.

18. In its discussion of the emergency news center (ENC), in SER § 13.3C.7.5 and the emergency operations facility (EOF) in SER § 13.3C.8.22 and SER § 13.3C.8.26, the Staff determined that the Crystal River-3 (Crystal River) ENC and EOF for LNP were acceptable because:

- **The NRC performs oversight of emergency preparedness, including the ENC and EOF, by monitoring performance indicators;**
- **The ENC and EOF are inspected periodically during routine inspections, drills, and exercises; and**
- **Any changes to the ENC and EOF are reviewed in accordance with the established inspection program and requirements for operating reactors.**

Given recent activities, including the Commission's issuance of exemptions that, in addition to other relaxations, remove the requirement for the identification of a physical location for dissemination of information from the Crystal River licensing bases, the facts underlying the Staff's assessment may have changed. In addition, Crystal River has submitted a certification of permanent cessation of operations. Because of that certification, Crystal River was removed from the reactor oversight process, eliminating monitoring of performance indicators and shifting from IMC 2515, "Light-Water Reactor Inspection Program-Operations Phase," to IMC 2561, "Decommissioning Power Reactor Inspection Program." Emergency preparedness is not a core inspection module under IMC 2561. There will be no further inspections on the Crystal River ENC and EOF. Changes to the Crystal River ENC and EOF would no longer trigger the 10 C.F.R. § 50.54(q) change process.

How, if at all, do these changes at CR-3 affect the Staff's acceptance of the Crystal River ENC and EOF for LNP as described in the SER?

Staff Response: Initially, the applicant proposed to use the Crystal River-3 EOF for support of emergency planning for LNP Units 1 and 2. The ENC is co-located with the EOF. The EOF and ENC were NRC-approved facilities for Crystal River-3 that met the applicable standards of 10 CFR 50.47 and requirements of Appendix E to Part 50, and conformed to the guidance in NUREG-0696, "Functional Criteria for Emergency Response Facilities," and NUREG-0737, Supplement No. 1, "Clarification of TMI Action Plan Requirements: Requirements for Emergency Response Capability."

Subsequent to the decommissioning of Crystal River-3, the EOF has been renamed the LNP EOF in the LNP Emergency Plan. By letter dated January 10, 2014, the applicant proposed EP ITAAC 7.2.3 through 7.2.5 to address regulatory guidance criteria in NUREG-0696 and Supplement 1 to NUREG-0737. Prior to fuel load, verification of completion of these EP ITAAC will ensure that the EOF is in compliance with the uniform building code; the EOF is environmentally controlled to provide room air temperature, humidity, and cleanliness appropriate for personnel and equipment; and the EOF is provided with industrial security when it is activated to exclude unauthorized personnel and when it is idle to maintain its readiness. Given that the EOF and ENC are not required to maintain functionality for some time prior to LNP operations, the Staff found these ITAAC necessary and sufficient to ensure that the EOF and ENC are available as described in the emergency plan.

Therefore, the Staff finds that with the inclusion of EP ITAAC 7.2.3 through 7.2.5, the changes at Crystal River-3 do not impact the Staff's acceptance of the EOF and ENC for the LNP as described in the SER.

19. Emergency Plan § H.4 (SER §§ 13.3C.8.4 (TSC), 13.3C.8.28 (EOF)) discusses activation and staffing of the emergency response facilities. This discussion establishes a "goal" of 60 minutes for the emergency response organizations (EROs) to achieve minimum staffing of the emergency operations facility (EOF) following the notification of an Alert (Site Area Emergency or general emergency). The discussion further states that applicable emergency response facilities will be operational within 15 minutes of achieving minimum staffing. The SER discussion

states that the LNP plan is acceptable because it conforms to the guidance in NUREG-0654 and Supplement 1 to NUREG-0737.

While compliance with the regulatory guidance is not required, please further explain the regulatory basis of the proposed alternatives for the following deviations from the following guidance:

- **NUREG-0737, Supplement 1, § 8.2.1.j states that the TSC will be "staffed by sufficient technical, engineering, and senior designated licensee officials to provide needed support and be fully operational within approximately 1 hour." Specifically, how will the Staff enforce this criterion when it appears to be treated as a goal, rather than an explicit licensee commitment?**

- **NUREG-0654 evaluation criterion B.5 states that "the licensee must be able to augment on-shift capabilities within a short period after declaration of an emergency." Specifically, the applicant states that the clock start time is the notification of the ERO.**

- **NUREG-0696 § 4.3 states, with regard to the EOF, "designated personnel shall report directly to the EOF to achieve full functional operation within 1 hour." Specifically, the applicant states that the facility will be operational within 15 minutes of achieving minimum staffing.**

Staff Response: Planning standard 10 CFR 50.47(b)(2) calls for adequate staffing to provide initial facility accident response in key functional areas to be maintained at all times, and for timely augmentation of response capabilities to be available. The Staff uses the minimum staffing guidance in Table B-1 of NUREG-0654/FEMA-REP-1 to evaluate on shift and augmented ERO staffing capabilities. It is recognized that an alternate staffing approach may be acceptable, provided that initial facility accident response in key functional areas is maintained at all times, and there is timely augmentation of response capabilities to support performance of the "Major Functional Areas" and "Major Tasks" listed in Table B-1 of NUREG-0654/FEMA-REP-1.

The guidance calls for a minimum on shift staff of 10 for one unit and 13 for two units, with the capability for additional staff of 11 in 30 minutes and 15 in 60 minutes. In Table B-1 of the LNP Emergency Plan the applicant commits to an on shift staff for one unit of 15, and for two units of 24, with a capability of an additional staff of 11 in 30 minutes and 16 in 60 minutes. The applicant's commitment provides for 5 staff in excess of the minimum on shift staff identified in the guidance for one unit and 11 staff in excess of the minimum identified in the guidance for two units, for initial facility accident response in key functional areas.

The need for additional staff in 30 or 60 minutes is somewhat mitigated by the fact that extra on-shift staff are available at the time of an event. Nevertheless, the applicant has committed to have a capability for additional staff at 30 and 60 minutes that is consistent with the guidance. The extra staff on shift, combined with a commitment for additional staff in 30 and 60 minutes, provides an acceptable alternative to, and exceeds, the guidance. It also provides an adequate basis for determining that the applicant has satisfied the regulatory standard for adequate staffing during initial facility accident response in key functional areas, and timely augmentation of response capabilities is available.

In emergency plan Section H.4, the applicant has stated that the response time capabilities are from when notification is made, and there is a goal of having emergency facilities operational within 15 minute of achieving minimum staffing. While the applicant chooses to refer to the augmentation times, and a 15 minute window to have the facility operational, as "goals" in Section H.4 of the emergency plan, in Sections B.1, B.5, and B.7, the applicant identifies the information in Table B-1 as "minimum staffing requirements." The reference to staffing times as "goals" in one section of the emergency plan does not negatively impact the ability to promptly augment and relieve on-shift staff, based on the assessment outlined above. The response time capabilities identified by the applicant are consistent with those approved previously by the Staff for other applicants and changes to on shift and augmentation staffing at existing operating nuclear power plants. The goals identified in the LNP Emergency Plan are a commitment by the applicant. Any changes to the LNP Emergency Plan will be governed by the 10 CFR 50.54(q) process. The licensee would need to get NRC approval if the licensee determines that a change to the LNP Emergency Plan would reduce the effectiveness of the emergency plan. Therefore, the Staff considers the staffing and augmentation times as stated as enforceable commitments.

20. Emergency Plan § J.12 "Registering and Monitoring Evacuees," states that LNP has the means for registering and monitoring all evacuees at relocation centers and that personnel and monitoring equipment will be made available to monitor all residents and transients. (This is not a responsibility assigned to the licensee; hence, it is not addressed in the SER.)

1. **This section appears to establish that the applicant has taken the responsibility for registering and monitoring evacuees. Is this correct?**

2. **Neither these personnel nor the equipment to be used have been previously identified in the emergency plan. Where are these resources being obtained from? In what time frame would they become available?**

3. **Has the Federal Emergency Management Agency reviewed these arrangements? If so, what was the result of its review?**

Response to be submitted by the applicant only.

21. Section 3.8.5.4 of the SER outlines how the RCC lifts are to be bonded and the bonding to be verified through testing. The ITAAC, however, in "Design Commitment," "Inspection, Test, and Analysis," and Acceptance Criteria" as described in Table 3.8-1, "Roller Compacted Concrete ITAAC," does not stipulate that the RCC Bridging Mat should be designed and perform for life as a monolithic section to avoid relative movements and sliding of individual lifts.

How will cohesion between lifts be assured, so that there is reasonable assurance that the RCC will behave as a monolithic structure following a safe-shutdown earthquake? Has this been inadvertently omitted from Table 3.8-1 "Roller Compacted Concrete ITAAC"?

Staff Response: In Section 3.8.5.11 of the FSAR, the applicant described the methods for constructing the RCC bridging mat, and the applicant committed to using bedding mix, placement, and compaction processes that are consistent with industry practices called out in USACE Engineering Manual 1110-2-2006. The RCC will be placed in lift thicknesses of approximately 1 foot. Bedding mix will be used over each entire lift surface for the RCC bridging mat construction. The USACE Engineering Manual 1110-2-2006, Section 5-7, "Lift Surfaces," describes the characteristics required for obtaining good RCC and bond strength at the lift joints. The Staff found that good quality aggregate, good mixture workability and compaction effort, rapid covering of lift joints by subsequent lifts, and the use of bedding mix provide reasonable assurance that the RCC will behave as a monolithic structure following a safe-shutdown earthquake.

Additionally, the applicant is committed to constructing a test pad with the specified RCC and bedding mixes. The test pad construction will use mixing, placement, and compaction procedures and equipment comparable to those that will be used during the LNP RCC bridging mat construction. Pursuant to License Condition 2.D(12)(g), the applicant is required to make available to the NRC, 180 days prior to construction, the 90-day test report for the Strength Verification and Constructability Testing program for this test pad.

Based on the Staff review in FSER Section 3.8.5, cohesion between lifts will be assured by the applicant's commitment to constructing a test pad and using the industry standard methods described above that have been successfully implemented on large commercial RCC projects. Therefore, no additions to the ITAAC are necessary. The ITAAC in Table 3.8-1 assures that the as-built RCC bridging mat conforms to the design described in the FSAR and will bridge over the karst features when subject to design basis loads without loss of structural integrity and the safety-related functions. In addition, the RCC in situ test pad described in FSAR Section 3.8.5.11 will be used for confirmation of lift performance and construction specification procedures to ensure the RCC is constructed as designed.

22. The introduction to SER Chapter 21 discusses the Staff's evaluation of the applicant's requested departures from the AP1000 certified design. The Staff states:

> **The staff evaluated each of the departures for impact on the LNP plant-specific probabilistic risk assessment (PRA). None of them have any impact on the quantification of core damage frequency or large release frequency. Only one (the departure relating to the passive core cooling system containment condensate return) resulted in a revision to any PRA-based insight.**

Please describe this revision to the PRA insight.

Staff Response: The table of risk insights from the AP1000 DCD states, "The PRHR HX, in conjunction with the PCS, can provide core cooling for an ***indefinite period of time***." [emphasis added]. The applicant performed an analysis to support design changes to the passive core cooling system condensate return system. With these changes, the analysis demonstrated that these systems can maintain the plant in a safe shutdown condition for ***at least 14 days***. [emphasis added]. The risk insights were updated to reflect this fact (i.e., change from "indefinite period of time" to "at least 14 days").

23. Chapter 21.0 concludes with the statement, "The staff finds that the cumulative risk impact of these design changes and departures is acceptable."

For the Staff: Please describe further how the Staff assessed the cumulative risk impact of these design changes and departures from AP1000 Design Control Document Rev. 19?

For the applicant: Has the applicant assessed the cumulative risk impact of the five design changes and departures listed in Chapter 21 of the SER as compared to AP1000 Design Control Document Rev. 19? If so, what were the results?

Staff Response: The Staff reviewed the applicant's determination of the risk impact of each change. Independently, the Staff qualitatively evaluated how each design change might be reflected in the PRA model. The Staff considered several factors:

- whether new combinations of component failure may result in system failure (revised fault trees)

- whether the estimated component failure frequency changed, including uncertainty (revised basic events)

- whether the system functional success criteria changed (revised thermal-hydraulic analysis)

The Staff found that a qualitative assessment was sufficient to confirm that the risk impact of each change would be much too small to affect the reported core damage frequency and large release frequency. Because the number of changes is limited, the cumulative risk impact of these design changes likewise remains too small to revise the risk assessment.

24. The Staff states the guidance in Regulatory Guide (RG) 1.82, Rev. 3, dated November 2003 and NEI-04-07, Rev. 0 were used in conducting the review of STD-COL 6.3-1. Regulatory Guide 1.82, Rev. 4, dated March 2012 was issued prior to the 2014 applicant-proposed changes in DEP 6.3-1 and specifically incorporated developments and lessons learned in the implementation of NEI-04-07, Rev. 0.

Please explain the rationale for using RG 1.82, Rev. 3 instead of Rev. 4 for this departure and exemption request. Did the applicant's submission and Staff's review incorporate lessons learned from implementation of NEI-04-07?

Staff Response: FSER Section 21.1.3, "Regulatory Basis," documents the regulatory basis applicable to the Staff's review of LNP departures and exemptions associated with changes to the passive core cooling system condensate return (i.e., LNP DEP 3.2-1 and LNP DEP 6.3-1). This regulatory basis section refers to STD COL 6.3-1 and its associated basis (i.e., RG 1.82 and NEI 04-07).

The reference to STD COL 6.3-1 and its associated basis in Section 21.1.3 is an error that resulted from a decision to change the location of the Staff's review of LNP DEP 3.2-1 and 6.3-1 from Chapter 6 to Chapter 21. As part of relocating the Staff's evaluation, the regulatory basis information appropriate to Chapter 6 (i.e., the associated basis for STD COL 6.3-1) was inadvertently copied into the regulatory basis in Chapter 21 for the review of LNP DEP 3.2-1 and 6.3-1.

The reference to STD COL 6.3-1 and its associated bases (i.e., RG 1.82 and NEI 04-07) in Chapter 21 did not have any bearing on the Staff's review and regulatory finding associated with LNP DEP 3.2-1 and LNP DEP 6.3-1 and therefore, is not necessary.

25. As a part of LNP DEP 3.2-1 and LNP DEP 6.3-1, the applicant describes the addition of protective screens to the downspouts to protect the passive residual heat removal heat exchanger (PRHR HX) from debris. Has the applicant or the Staff investigated whether the screens could be subject to clogging phenomena similar to what is considered by Generic Safety Issue 191 (GSI-191)? Has the applicant performed any analysis to determine how long the PRHR HX can remain functional with degraded return flow to the incontainment refueling water storage tank (IRWST)?

<u>Staff Response</u>: With respect to the potential for screen blocking phenomena similar to that seen in GSI-191, the Staff considered various issues in evaluating the acceptability of the gutter downspout screens. First, those events relying upon the PRHR system and the downspout screens as a source of core cooling are non-loss of coolant accident events where the IRWST water eventually boils (i.e., these events do not include pipe breaks). As a result, the only debris generation mechanism for these events is via condensate flow along the walls and/or through the gutter system. Coatings along the containment walls are the only coatings with the capability to transport, and these coatings are made of inorganic zinc that is qualified for the post-accident environment. The only debris expected to reach the downspout screens would be latent containment debris, which is limited to a very small amount for the AP1000 and is controlled by a containment cleanliness program. As such, the downspout screens are not expected to be impacted by debris. Additionally, the gutters are periodically inspected for cleanliness, per Technical Specification Surveillance Requirement 3.5.4.7. Nevertheless, in the event that any single downspout is blocked, the gutter piping is sized such that the other downspouts can accommodate all the flow, even under the maximum flow condition.

The Staff performed confirmatory analyses as part of the review which included a sensitivity study to investigate the impact of a reduced condensate return rate on the acceptance criteria for the bounding 72 hour event. The results of these analyses showed that the condensate return rate has substantial margin with respect to the acceptance criteria.

26. In RAI 7439, the Staff inquired about the applicant's use of extrapolated predictions of condensate return losses. SER § 21.1.4 states that "the NRC staff remains unconvinced as to the validity of the applicant's temperature scaling argument, especially given the relative variance in the test results," although the Staff went on to find that the treatment of condensate losses over the attachments to the containment shell was acceptable due to conservatism in the extrapolation.

1. **For the applicant, please discuss further the justification for using extrapolated predictions.**

2. **For the Staff, please explain the Staff's justification for the finding that "the treatment of film losses over attachments to the containment shell" is acceptable.**

<u>Staff Response</u>: The Staff concluded that the assumed condensate film losses over attachments was acceptable due to the degree of conservatism in the values used in concert with a sensitivity study performed by the applicant. The sensitivity study demonstrated that a further increase in film losses had a negligible impact on the PRHR performance early in the transient (before 72 hours) and only a minor reduction in the duration of PRHR performance in the longer term (greater than 14 days). The Staff issued an RAI requesting the applicant to provide a basis for the extrapolation of the condensate return loss rates at lower temperatures, to the higher temperatures of the post-accident containment environment. In its response (ADAMS Accession No. ML14182A106), the applicant performed a sensitivity study on the effect of additional condensate return losses over the attachment plates. The sensitivity study showed that the PRHR heat exchanger uncovered less than 5 percent sooner as compared with the base analysis and that the system's performance was not affected until after 14 days. In addition, the applicant showed that the loss rates in the test facility were expected to be higher than those in the post-accident environment in containment, and therefore the actual loss rates are expected to be substantially lower than the extrapolated values used in the analysis.

27. As part of the exemption for DEP 3.2-1 related to the passive core cooling system (PXS) containment condensate return, Technical Specification (TS) Surveillance Requirement 3.5.4.7 was added to require a visual inspection of the IRWST gutter and downspout screens to verify that the return flow to the IRWST will not be restricted by debris.

The Staff's technical evaluation of the exemption request and departure states, "Condensate return is one of the primary factors influencing the performance of the PRHR HX." The Staff further explains that the PXS downspout piping network was added at the polar crane girder and stiffener with four specific collection points located on both the upper portion and the lower flange of the polar crane girder. While in use during refueling or forced outages the polar crane can be positioned at any point on the girder.

Does the final polar crane bridge position on the girder (relative to the 8 downspout screens on the polar crane girder and internal stiffener) affect the rate of return of condensate from the polar crane bridge via the gutter system or is the rate of condensate return unaffected by polar crane bridge position?

If the final polar crane bridge position on the girder affects the rate of return of condensate to the IRWST, please explain why a TS Surveillance Requirement for polar crane position is unnecessary to ensure that the quality of systems and components is maintained and the limiting conditions for operation will be met for the PXS.

If the final polar crane bridge position on the girder affects the rate of return of condensate to the IRWST, are restrictions on polar crane position relative to TS operational MODES required?

<u>Staff Response</u>: Condensate flow is not impacted by the position of the polar crane because there is no offset where the crane itself impacts the water flow along the containment shell and where the collection points or guttering is located. The applicant deliberately considered this during the design change to ensure that the crane itself was not affected, and to ensure that the condensate flow is not impacted by the crane.

28. **The Staff discusses the tube plugging assumption used for DBA analyses along with the analysis of the Loss of AC Power to Plant Auxiliaries (LOAC). The Staff notes that the analyses of the LOAC event demonstrate that the top horizontal portion of the PRHR heat exchanger becomes uncovered.**

    Did the tube plugging assumptions conservatively assume that the plugged tubes were not within the top horizontal portion of the PRHR heat exchanger that becomes uncovered? If not, please explain why this additional conservatism was unnecessary.

Staff Response: The PRHR heat exchanger, shown in Figure 6.3-5 of the AP1000 DCD, consists of 689 C-shaped tubes. Each tube has an upper horizontal section, a vertical section, a lower horizontal section, and two 90 degree bends. Therefore, it is not possible to have a tube plugged in only the upper or lower horizontal sections of the heat exchanger because each tube is continuous, and if a tube is plugged anywhere it does not contribute to heat transfer. The Staff performed confirmatory analyses as part of the review, which required the development of a PRHR heat exchanger model. In developing this model, the Staff analyzed the impact of plugging the outer-most tubes versus the inner-most tubes of the PRHR heat exchanger. This analysis, combined with additional sensitivity studies conducted by the Staff, demonstrated that PRHR performance was not sensitive to which tubes were plugged.

29. **The design requirement of establishing an initial long term safe shutdown condition within 36 hours (i.e., reaching an average reactor coolant system (RCS) temperature less than 420°F in 36 hours) following an event with a safety grade decay heat removal system is established in the EPRI utility requirements document (URD) and SRM-SECY-94-084. SECY-94-084 states that after the passive residual heat removal system affects the initial shutdown condition, a non-safety grade reactor shutdown cooling system will be available to bring the plant to cold shutdown conditions for inspection and repair.**

    In SER § 21.1.4.B.1.2.5, "Safe Shutdown," the Staff discusses the safe shutdown criteria for reaching an average RCS temperature of less than 420°F in 36 hours. In SER § 21.1.4.B.1.3, "Non-Safety Design Basis," the Staff states that the PRHR heat exchanger long-term shutdown condition for 14 days in a closed loop mode of operation are non-safety related operational requirements.

    In FSAR § 6.3.1.2.1, "Nonsafety Design Basis-Post Accident Core Decay Heat Removal," the applicant describes both establishment of the reactor coolant temperature of 420°F in 36 hours and a long-term shutdown condition of 14 days at 420°F as non-safety related. In an April 5, 2016, presentation (slide 15) to the Advisory Committee on Reactor Safeguards on the PXS condensate return, the applicant again stated that the PRHR establishment of the reactor coolant temperature of 420°F in 36 hours and a long-term shutdown condition of 14 days at 420°F are "nonsafety" design basis licensee performance goals.

While not a Chapter 15 design basis accident safety requirement, the establishment of the reactor coolant temperature of 420°F in 36 hours appears to be a safe shutdown safety-related requirement from SER § 21.1.4.B.1.2.5, with criteria as discussed in SECY-94-084. Please explain the discrepancy between the Staff's SER and applicant's FSAR regarding whether the performance criteria for the initial establishment of the reactor coolant temperature of 420°F in 36 hours is a safe shutdown safety-related equipment performance requirement or a non-safety design basis requirement. Were the calculations and analyses performed by the applicant/vendor completed as part of a 10 C.F.R. Part 50, Appendix B program?

<u>Staff Response</u>: There is no discrepancy between the Staff's SER and the applicant's FSAR. The Staff states, in Section 21.1.4.B.1.2.5 of the SER, "Safe Shutdown," that the applicant's changes under FSAR 6.3.1.1 clarify how the design requirement of cooling the reactor coolant system below 420 ºF within 36 hours is met. These changes include modifications to FSAR Section 6.3.1.1.1, "Emergency Core Decay Heat Removal," and modifications to FSAR Section 6.3.1.1.4, "Safe Shutdown." The changes under FSAR 6.3.1.1 attempt to clarify that the design requirement of cooling the RCS below 420 ºF within 36 hours is not a safety function, and that it is demonstrated using a more realistic analysis. The analyses conducted to support LNP DEP 3.2-1 and LNP DEP 6.3-1 were performed by the applicant as part of a 10 CFR Part 50, Appendix B program.

Cooling the reactor coolant system below 420 ºF within 36 hours is not required by regulation and is nonsafety because a failure to meet this requirement does not result in any adverse consequences. SECY-94-084 states that passive system capabilities can be demonstrated by appropriate evaluations including a safety analysis to demonstrate that the passive systems can bring the plant to a safe stable condition and maintain this condition. During the review of LNP DEP 3.2-1 and LNP DEP 6.3-1, the applicant demonstrated compliance with 10 CFR Part 50, Appendix A, General Design Criterion 34 by submitting a bounding safety analysis that demonstrated a safe, stable condition (i.e., reactor subcriticality, decay heat removal, and radioactivity containment) was maintained by the passive core cooling system for a duration exceeding 72 hours. This safe, stable condition was maintained at a temperature above 420 ºF. This informed Staff that cooling the RCS below 420 ºF within 36 hours is not a safety function because failure to meet this requirement does not result in any adverse consequences.

30. The main control room (MCR) radiation monitors are deenergized on either a High-2 radiation signal (MCR emergency habitability system (VES) actuation) or a low battery charger input voltage for greater than 10 minutes. Therefore, following an actuation of the High-2 radiation signal, the MCR radiation monitors no longer function to provide operators in the control room with real-time radiation readings.

Continuous MCR radiation measurements with automatic alarm setpoints available to operators during an accident ensure the control room provides a safe environment for operators under accident conditions and that operators know the MCR emergency habitability system (VES) filtration system is properly functioning following a valid actuation.

Additionally, Emergency Action Level "AA3" for an ALERT due to abnormal radiation levels in the NRC endorsed NEI 07-01, Rev. 0, describes an example

emergency action level threshold dose rate of greater than 15 mRem/hour in the AP1000 MCR. The emergency action level basis description states the value of 15 mRem/hour is derived from the General Design Criteria 19 value of 5 Rem in 30 days.

Are continuous MCR radiation monitors needed to determine whether an Emergency Action Level is met in the AP1000 MCR under all conditions? Please explain why de-energization of the MCR radiation monitors following a High-2 radiation signal or a low battery charger input voltage for greater than 10 minutes is acceptable.

Staff Response: As certified, the AP1000 MCR radiation monitoring system is installed on the nonsafety-related NI nonradioactive ventilation system (VBS), which provides outside air to the MCR. The MCR VES is a passive system that provides clean bottled air to the MCR and provides for recirculation of the MCR atmosphere through the VES filter. The VES does not share pipes or ducts with the VBS. VBS is isolated upon initiation of VES, which includes isolation of the MCR outside air intakes. The radiation monitor sample line connections are upstream of the VBS supply air isolation valves. This means that when the VES is in operation the MCR radiation monitors are no longer in line to be able to monitor the air in the ventilation system which supplies the MCR. DCD Table 6.4-2 describes other means for the control room operators to identify that the VES is operating as expected to ensure control room habitability during accidents (e.g., VES air delivery line flowrate indication and high and low alarms).

In RAI Letter 130, Question 12.03-7 (ADAMS Accession No. ML15219A536), the Staff asked a similar question from the perspective of 10 CFR Part 20, Subpart F, which requires licensees to make surveys of areas necessary for the licensee to comply with the regulations and to evaluate the magnitude and extent of radiation levels. The applicant's response, by letter dated November 2, 2015 (ADAMS Accession No. ML15308A383), stated that the design of the MCR radiation monitors, including consideration of the conditions that result in their de-energization as noted in this question, was not changed from the design certification and has finality. The applicant further stated that adequate monitoring of the radiation levels within the MCR would be achieved through use of portable radiation monitoring equipment such as a Geiger-Muller probe or other survey instrument, or through a grab sample of the MCR atmosphere during periods when the permanently installed radiation monitor is unavailable. Such portable radiation monitoring equipment would also be able to detect radiation levels for the purposes of monitoring for information pertinent to the emergency action level scheme.

The Staff has approved an emergency action level (EAL) scheme for LNP using NEI 07-01, Revision 0, "Methodology for the Development of Emergency Acton Levels – Advanced Passive Light Water Reactors," in combination with License Condition 13-4 which states, "No later than one hundred eighty (180) days before the date scheduled for initial fuel load set forth in the notification submitted in accordance with 10 CFR § 52.103(a), the licensee shall submit to the Director of NRO, or the Director's designee, in writing, a fully developed set of plant-specific EALs for LNP Unit [1 and 2], in accordance with NEI 07-01 with no deviations. The EALs shall have been discussed and agreed upon with State and local officials." FSER Section 13.3C.4 provides the Staff's review of the emergency classification system, including the acceptability of this license condition.

The ventilation systems that serve the MCR are built to meet GDC 19 with operation of the VES. EALs are developed to meet 10 CFR 50.47(b)(4) and 10 CFR Part 50, Appendix E, with the Staff's finding based on 10 CFR 50.47(a). For the EAL related to MCR radiation levels (AA3), the Staff expects the licensee would implement the EAL as written in NEI 07-01, Revision 0, in accordance with the applicable license condition and that the licensee would declare EAL AA3 when the MCR area radiation monitor (RMS-JE-RE010) indicates a dose rate greater than 15 milli-Roentgen per hour (mR/hour). If, for whatever reason, RMS-JE-RE010 becomes unavailable, then the licensee must implement a compensatory measure, which could be through use of a temporary (portable) monitor. It is specifically required by 10 CFR 50.54(q)(2) that the licensee maintains the effectiveness of its emergency plan, which for EALs means that this instrument is maintained, or implementation of some temporary compensatory measure is needed. It is important to note that in the event of an actual radiological event that results in a High 2 Radiation Signal, there should already be an EAL declared based upon this radiological event, and that EAL would either be an Alert, Site Area Emergency, or General Emergency depending on the integrity of fission product barriers. As a result, the need to monitor conditions for EAL AA3 (alert) would be unnecessary.

31. Stage 1 load shed de-energizes large screen displays used for weather and the non-safety-related MCR area radiation monitor. The applicant and the Staff conclude that the stage 1 load shed does not affect operational decision making or plant control.

Please explain further the effect, if any, that the stage 1 load shed has on operational decision making in the context of emergency plan implementation by operators with the loss of large screen displays for weather and the non-safety-related MCR area monitor.

<u>Staff Response</u>: The emergency plan does not credit the availability of the large screen displays for weather; those displays would shut down as a result of Stage 1 load shed. Weather information is provided by instrumentation located on a site meteorological tower. The emergency plan, Section H.8, “Meteorological Instrumentation and Procedures,” describes the information provided by this tower. Real time meteorological data will be digitally displayed in the Control Rooms, with provisions for computerized historical storage and retrieval, for use in accident scenarios. If these parameters are not available, then met data is obtained from the National Weather Service (NWS). The intent of real-time meteorological data for the emergency plan is for dose projections used for Protective Action Recommendation (PAR) development and for several EALs. The dose projection system is program-based and does not rely on the large screens for implementation. However, in the event that the meteorological instrumentation fails, or is otherwise out of service, using data from the NWS would be an acceptable compensatory measure. For EALs, while using dose projections to inform EAL decision-making is preferred, the capability of using calculated values from other instrumentation is maintained in case dose projections are unavailable.

Prior to VES actuation, MCR radiation levels are provided by two independent MCR air duct monitors that continuously measure radiation levels in the MCR supply air duct. The monitors are safety related and provide control room indication for gaseous, particulate, and iodine radioactivity concentration in the MCR supply air duct. The emergency plan, Section 2.1, “Radiation Monitoring,” (page I-1) lists the radiation monitors included in the emergency plan and includes these monitors. Subsequent to VES actuation the control room is isolated by design, and only bottled air is being released to the control room to maintain air quality. Temperature is maintained by passive heat removal using the control room walls acting as the heat sink. In RAI Letter 130, Question 12.03-7 (ADAMS Accession No. ML15219A536), the Staff asked how control room radiation levels were monitored post VES actuation. The applicant stated that adequate monitoring of the radiation levels within the MCR would be achieved through use of portable radiation monitoring equipment such as a Geiger-Muller probe or other survey instrument, or through a grab sample of the MCR atmosphere during periods when the permanently installed radiation monitor is unavailable.

For the EAL related to MCR radiation levels (AA3), the Staff expects the licensee would implement the EAL as written in NEI 07-01, Revision 0, in accordance with the applicable license condition and that the licensee would declare EAL AA3 when the MCR radiation monitor (RMS-JE-RE010) indicates a dose rate greater than 15 mR/hour. If, for whatever reason, RMS-JE-RE010 becomes unavailable, then the licensee must implement a compensatory measure, which could be through use of a temporary (portable) monitor. It is specifically required by 10 CFR 50.54(q)(2) that the licensee maintain the effectiveness of its emergency plan, which for EALs means that this instrument is maintained, or implementation of some temporary compensatory measure is needed. It is important to note that in the event of an actual radiological event that results in a High 2 Radiation Signal (and the eventual load-shed resulting from the increasing MCR heat load), there should already be an EAL declared based upon this radiological event, and that EAL would either be an Alert, Site Area Emergency, or General Emergency depending on the integrity of fission product barriers. As a result, the need to monitor conditions for EAL AA3 (alert) would be unnecessary.

The Staff's response to Question 30 provides additional information on the interface of MCR radiation monitoring with EALs.

32. The Staff concludes that "there is reasonable assurance that Scenarios 4, 5, and 9 will not occur because of the low probability of concurrent independent failures," recognizing many of the scenarios may be considered beyond design basis.

Please provide additional information on the expected probability of occurrence of the scenarios presented in Table 21.3-1 and a further explanation of why there is reasonable assurance Scenarios 4, 5, and 9 will not occur.

<u>Staff Response</u>: The probability of occurrence was qualitatively assessed for Scenarios 4, 5, and 9. The scenarios are beyond the licensing basis for the AP1000 design and were only used to establish a worst-case condition. The worst-case conditions were used to demonstrate that even under these conditions, a plant shutdown would be required by Technical Specifications within 26 hours of the initiating condition. This minimizes the time at power when the wide panel information system plays an important part in event diagnosis. It is the low probability of event occurrence combined with the minimum time at power that supports the conclusion of reasonable assurance of safety.

While the scenarios are unlikely, they were not omitted from the evaluation. A quantification of their probability of occurrence was not considered necessary.

33. Discuss any issues of special interest that arose from the Staff's review of LNP as a "greenfield" site.

<u>Staff Response</u>: The review of the LNP site did not present any special issues because it was a "greenfield" site. The Staff's review guidance in the Environmental Standard Review Plan (NUREG-1555) does not assume either a "greenfield" or a "brownfield" site. Rather, the Staff is directed to consider the environmental impacts of the action, regardless of the previously existing condition of the site. The LNP site is less disturbed than a typical industrial "brownfield" site, such as a site with operating nuclear power units. But the LNP site has been in use for active forest management for some time, and is not pristine. For comparison, much of the affected land on existing reactor sites proposed for new reactors (e.g., Fermi Unit 3 or Calvert Cliffs Unit 3) is naturally vegetated buffer lands that must be addressed in a manner similar to naturally vegetated lands on "greenfield" sites.

34. For the Staff: How is the NRC Staff keeping track of and considering changes that have occurred since publication of the final environmental impact statement (FEIS) (April 2012) to determine whether to supplement the FEIS?

- **Describe the process the Staff is using to monitor and evaluate changes that may occur during the time period between publication of the FEIS and the Commission licensing decision, which has spanned several years.**

- **Do any events—such as the Duke Energy-Progress merger, the overall delay in LNP's construction and commercial date of operation schedule, or the closure of Crystal River—present a seriously different picture of the environmental impact of the issuance of the COLs from what was previously envisioned?**

For the applicant: How has the applicant kept track of changes that have occurred since publication of the FEIS and kept the Staff apprised of these changes?

Staff Response: The Staff used its New and Significant Process to identify potentially significant new information after the FEIS was issued to: (1) identify new information, (2) evaluate and document the new information to determine if it is significant, and (3) determine whether supplementation is required. This process is described in "Staff Process for Determining if a Supplement to an Environmental Impact Statement is Required in Accordance with Title 10 of the Code of Federal Regulations, Part 51.92(a) or 51.72(a)" (ADAMS Accession No. ML13199A170). The guidance addresses situations in which there is an extended delay (e.g., more than a year) between issuance of the FEIS and the onset of the mandatory hearing to track new information and determine whether it requires a supplement to the FEIS under 10 CFR 51.92.

As part of this post-FEIS review for LNP, the NRC staff conducted an audit on February 10, 2016, of the applicant's process for identifying and assessing new information (ADAMS Accession No. ML16091A415). The Staff concluded that the applicant had an acceptable process. As part of the new and significant review the Staff evaluated new information such as the Duke Energy-Progress merger, the overall delay in LNP's construction and commercial date of operation schedule, and the closure of Crystal River to determine if it presented a seriously different picture of the environmental impact of the issuance of the COLs from what was previously envisioned in the FEIS. The merger is a change in ownership which would not have an environmental impact. The analysis of the need for power relies on conditions that were in effect at the time the FEIS was written, therefore the delay in construction and operation date and the closure of Crystal River were evaluated for their significance. The closure of Crystal River removed 860 MW of capacity from the DEF fleet, which would in and of itself not have affected the conclusions of the need for power analysis because less capacity would reinforce the need for power from the Levy plant. Other factors changed as well—planned capacity additions and closures that had not been identified before FEIS publication—that could affect the need for power conclusion. However, the Staff finds the conclusions in the FEIS have not changed: there is a need for the 2,200 MW of capacity from the LNP.

The Staff also evaluated the closure of Crystal River for its effect on the alternative site analysis. The determination was that the Crystal River site would still be a viable alternative site and the closure would not change the conclusion that Crystal River would not be an environmentally preferable site.

In the FEIS, the Staff prepared an independent analysis of the impact of discharge from the proposed LNP and existing Crystal River units on temperature and salinity within the Gulf of Mexico. As part of the new and significant review, the Staff also analyzed effects of the closure of Crystal River on LNP discharge scenarios and the resultant temperature and salinity impacts on the Gulf of Mexico. The Staff concluded that this information was not significant.

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

35. Did the Staff consider whether any new information would warrant supplementation under the discretionary standard set forth in 10 C.F.R. § 51.92(c)?

Staff Response: 10 CFR 51.92(c) states that the NRC staff may prepare a supplement to a FEIS when, in its opinion, preparation of a supplement will further the purposes of the National Environmental Policy Act (NEPA). In addition to its determination that no new information was found to be significant such that a supplement was warranted, the Staff did not identify any circumstances that would warrant supplementing the FEIS under 10 CFR 51.92(c).

36. One of the new pieces of information that the Staff considered in its Consideration of New Information Regarding the Crystal River Alternative Site ("New and Significant Review") (ML16060A186) is that a new combined-cycle plant named Citrus County Combined-Cycle Project (CCCP) has been proposed and would be located adjacent to the Crystal River Energy Complex. The Staff states on page 3 of the New and Significant Review that the CCCP footprint appears to overlap with the footprint for the nuclear plant at the Crystal River alternative site. The Staff concludes, however, that "there appears to be ample land available to the

applicant to adjust the placement of the nuclear units if the Crystal River alternative site were to be used." Did the Staff consider what specific site reconfigurations would be necessary to accommodate both facilities? Explain how the Staff evaluated whether such reconfigurations would alter or intensify impacts to cultural resources, sensitive habitats (such as wetlands), or other environmental resources.

Staff Response: The amount of overlap between the new site for the CCCP and the Crystal River alternative site would be small. It is likely a new nuclear plant could be built on the alternative site as it was proposed in the COL application. However, if additional land was needed, there is a considerable amount of undeveloped land adjacent to the alternative site that could be obtained. This land is similar in nature to the land on the proposed site. Therefore, the Staff expects that the environmental impacts of the use of such land would be similar to those evaluated in the FEIS. The Staff did not develop specific reconfigurations because it is not clear that any such changes in configuration would be necessary. The Staff considers this approach to be consistent with the use of reconnaissance level information for the alternative sites, as discussed in the Environmental Standard Review Plan (NUREG-1555), Section 9.3.

37. Duke Energy issued a revised wetland mitigation plan dated September 2015 (ML15294A201). In its consideration of new information regarding the revised wetland mitigation plan (ML15327A349), did the Staff coordinate with the U.S. Army Corps of Engineers (USACE) regarding whether information in the revised wetland mitigation plan would require supplementation of the FEIS? If not, why not? And if so, what were the results of that consultation?

Staff Response: The NRC staff informally communicated with USACE staff regarding the revised wetland mitigation plan, but the two agencies reviewed the revised plan, as it relates to the proposed action of each agency, separately. The focus of the NRC review was whether the revised wetland mitigation plan contained new and potentially significant information requiring supplementation of the FEIS under the NEPA. The USACE review focused on whether the revised wetland mitigation plan satisfies the requirements for a Department of the Army permit under the Clean Water Act. The NRC staff concluded that the new information contained in the revised wetland mitigation plan does not meet either of the criteria in 10 CFR 51.92(a) that would require NRC to supplement the FEIS.

38. The revised wetland mitigation plan includes the clearing and excavation of 91 acres of upland habitat for the purposes of wetland creation. Because wetland creation was not an element of the original plan, explain how the Staff evaluated the potential impacts of this upland habitat loss on ecological resources and specifically on the Florida scrub-jay, an endangered species for which the U.S. Fish and Wildlife Service (FWS) issued a Biological Opinion (ML113530504) in December 2011.

Staff Response: The NRC staff's review of the revised wetland mitigation plan for new and potentially significant information under the NEPA considered the proposed clearing and excavation of 91 acres of upland habitat for the purposes of wetland creation. Subject matter experts with the NRC staff read the revised wetland mitigation plan, met with representatives of the applicant and USACE on the site to discuss the plan and observe affected areas, and evaluated the changed environmental impacts and benefits likely to result from implementation of the revised versus original plan. The NRC staff's review concluded that the mitigation will convert uplands with a history of intensive pine silviculture to wetland forests typical of the surrounding region that will provide improved wildlife habitat and help shield adjoining natural wetlands from runoff and sedimentation and therefore result in a net ecological benefit. None of the affected upland areas support habitat favorable for the Florida scrub jay. The proposed wetland creation is limited to certain upland areas on the site. According to the FEIS, the xeric, well-drained scrub habitats preferred by scrub jays are lacking on the site (FEIS at 4-53). The Biological Opinion (BO) also indicates that activities on the LNP site are not expected to result in adverse effects to the Florida scrub-jay or its habitat.

The NRC staff will issue an Environmental Protection Plan (EPP) as part of the combined license that will outline the specific monitoring and mitigation measures established by FWS in the Incidental Take Statement (ITS) in the BO issued to NRC under Section 7 of the Endangered Species Act (ESA). The Environmental Protection Plan will require the applicant to resurvey potentially suitable habitat for the Florida scrub-jay and other relevant species indicated in the BO within two years prior to any land clearing or construction, as established of the BO and ITS. The EPP will also require the applicant to avoid, to the maximum extent practicable, work in potential scrub-jay habitat during the nesting season extending from March 1 through June 30 and to notify NRC of any unauthorized take of scrub-jays, as established in the BO and ITS. No other mitigation or monitoring requirements are established in the BO and ITS.

39. Considering that USACE is a cooperating agency on the environmental review, and that the Least Environmentally Damaging Practicable Alternative (LEDPA) review was ongoing at the time the Staff issued the FEIS, how was the NRC able to finalize the FEIS well before the outcome of the LEDPA determination?

- **Has the USACE completed its LEDPA?**

- **If the LEDPA has been completed, did the NRC Staff evaluate the LEDPA to determine if it contained new and significant information that would require the Staff to supplement the FEIS?**

If the LEDPA review has been completed, did it result in any significant changes to the plant design?

Staff Response: The NRC and USACE review team was able to finalize and issue the FEIS prior to the USACE LEDPA determination, as the findings documented in the FEIS do not depend on it. The USACE issued its Department of the Army permit for the LNP project on December 30, 2015. In order to issue the permit, the USACE had to conclude that the LNP site was the LEDPA, but did not issue a standalone LEDPA evaluation.

For its review of new information, the Staff reviewed documentation for the project as it is currently planned. For example, Duke Energy Florida, Inc. (DEF) adjusted the alignment of the access road in response to concerns raised by the USACE. This change was considered by the NRC staff as part of its review of new information. There were no significant changes identified by the Staff that warranted a supplement to the FEIS. The NRC staff used the same information regarding environmental impacts in its NEPA evaluation that was used in the USACE LEDPA evaluation.

40. What are "Conditions of Certification" and did the NRC consider them in its environmental review?

The Conditions of Certification (ADAMS Accession No. ML110340086) are binding requirements imposed by the State of Florida on the applicant that address construction and operation of the LNP and associated offsite facilities. The NRC staff considered the requirements in the Conditions of Certification in development of its analysis of reasonably foreseeable environmental impacts throughout the FEIS. The Staff also frequently cited and discussed requirements from the Conditions of Certification in the FEIS (see, e.g., FEIS at 2-87, 2-124, 4-13, 4-21, and 5-5).

41. In Chapter 1, the FEIS states that the NRC contacted Tribal organizations. Explain how the NRC Staff engaged Tribal organizations.

Staff Response: The Staff engaged the Tribes in consultation under Section 106 of the National Historic Preservation Act and in additional correspondence. The NRC's consultation and correspondence efforts are described in Section 2.7.3 of the FEIS. The Staff sent letters to the Miccosukee Tribe, the Seminole Tribe of Florida, the Seminole Tribe of Oklahoma, the Perdido Bay Tribe of Lower Muscogee Creeks, and the Muscogee Nation of Florida. In the letters, the Staff provided the Tribes information about the proposed action. The letters also invited the Tribes to identify concerns; provide information on the evaluation of historic properties of traditional, religious, and cultural importance; and participate in the resolution of any adverse effects to such properties.

The Miccosukee Tribe responded on December 10, 2008, stating it had no direct knowledge of cultural resources within the project area, but recommended that cultural resource surveys be conducted (see ADAMS Accession No. ML090120781). The NRC responded by letter dated August 25, 2009 (ADAMS Accession No. ML092120229), providing information regarding cultural resources surveys conducted by PEF. The Seminole Nation of Oklahoma, in response to the NRC's consultation letter, asked that the NRC work through the Seminole Tribe of Florida for development of the FEIS and to keep their Tribe informed.

On October 22, 2010, the review team of the NRC and the USACE met with the Seminole Tribe of Florida (STOF) to discuss issues related to cultural resources for both the proposed Turkey Point Units 6 and 7 and the proposed LNP. At this meeting, the STOF expressed interest to the review team regarding the transmission lines from the proposed LNP project and requested maps, which the NRC provided by letter dated August 12, 2011 (see ADAMS Accession No. ML110970624). The USACE also conditioned its permit to require cultural resource surveys to be conducted prior to initiating ground-disturbing activities for various components of the project in the USACE permit area, including construction of the transmission lines. The review team's investigation and outreach and the information from each agency's consultation, as described in FEIS Sections 2.7.2 and 2.7.3 and Appendix E responses to comments, informed the thoroughness of the overall analysis and conclusions about impacts to historic and cultural resources and its engagement with Tribal organizations.

42. The FEIS at page 2-116 references NMFS's current Biological Opinion for the Crystal River Energy Complex. However, the reference "NMFS 2002" is for an NRC letter forwarding the Biological Opinion and does not contain the Biological Opinion, itself. Please provide the appropriate citation to the opinion. How did the NRC Staff use this Biological Opinion during its assessment of impacts to federally listed species?

Staff Response: The FEIS on page 2-116 does cite a letter of transmittal from B. Mozafari, NRC, to D. Young, Crystal River Nuclear Plant (ADAMS Accession No. ML02249224), forwarding the August 8, 2002, BO for the Crystal River Energy Complex from the National Marine Fisheries Service (NMFS). The ADAMS accession number in the FEIS provided only the letter of transmittal and did not include the 34 page BO. A separate August 8, 2002, letter of transmittal from J. Powers, NMFS, to H. Berkow, NRC, (ADAMS Accession No. ML022460361), contains the complete BO.

The Staff used the BO to provide general descriptive information on sea turtles in Section 2.4.2.3 of the LNP FEIS. Information about the distribution, relative abundance, and life history was used to characterize the aquatic resource in Crystal Bay. The information in the BO was, however, of limited value in assessing the impact of the LNP on sea turtles. The two units at the LNP site will use closed-cycle cooling, and the through-screen intake velocities will be low enough that impingement or entrapment of juvenile or adult sea turtles will be minimal and no further mitigation would be warranted.

43. The descriptions of the sea turtles at pages 2-117 and 2-118 include incidental take information for each species. Though the NRC receives real-time information and licensee event reports on each incidental take, the data cited is from NMFS technical memoranda that date back to 2005. Additionally, the numbers of incidental takes cited for loggerheads and Kemp's ridley turtles appear to be incorrect. In addition, the text says that the hawksbill turtle has never been reported at Crystal River; however, there was a hawksbill incidental take on 11/28/00 (see ML030070080, p. 4).

Please reconcile the information in the FEIS with the NMFS technical memoranda and the Environmental Plan Protection Report referenced above. Please discuss whether the Staff has reviewed any updated information regarding incidental takes of sea turtles at Crystal River and whether that information would require updating the FEIS.

<u>Staff Response</u>: The sea turtle annual reports from Crystal River provided in FEIS Section 2.4.2.3 contribute to a reasonable characterization of the aquatic resources in Crystal Bay. This information can be considered a sampling method providing additional distribution, relative abundance, and life history information, and was used to characterize the aquatic environment near the LNP site. However, given the substantial differences in cooling system design between the LNP and Crystal River units (namely, LNP's proposed closed-cycle cooling system vs. Crystal River's once-through cooling system), which greatly reduces the potential for impingement and entrapment of aquatic species, the Crystal River sea turtle data has limited value in predicting impacts associated with the operation of the LNP intake.

The Staff did check the CREC sea turtle annual reports and found that one hawksbill turtle (*Eretmochelys imbricata*) had been collected alive on November 28, 2000. However, this information did not warrant any revision to the analysis in the FEIS, nor has the Staff continued to monitor sea turtle annual reports as part of the environmental review for the LNP after publication of the FEIS. Tracking and revising this information was not necessary in order to accurately characterize the reasonably foreseeable impacts due to operation of the LNP cooling system, which is designed significantly differently from the Crystal River cooling system such that impacts to sea turtles would be minimal. The information in the Crystal River reports was used as one source of data to describe the aquatic environment near the LNP site. Numerical precision in analyzing the sea turtle annual reports is not necessary or useful to assessing impacts from the LNP. Therefore, it is unlikely that additional data or analysis of the data from Crystal River (which is currently not operating) would result in a need to update or supplement the FEIS.

44. At the top of page 2-159, please describe the information that is captured in Tables B02001, B03003, and C17002.

<u>Staff Response</u>: The referenced tables are a part of the U.S; Census' American Community Survey 5-Year Summary Files for 2005 to 2009. These files contain a variety of data at geographic levels from state-wide to the census block level. The text on page 2-159 states:

> "Unless otherwise specified in the sections below, the review team used data from the Bureau of Census Tables B02001, B03003, and C17002 5-year estimate data for the years from 2005 to 2009 (USCB 2011.) Where the review team used different analytical methods or additional information for its own analysis, the sections below include explanatory discussions and citations for additional sources."

The 2005-2009 ACS 5-Year Summary File Technical Documentation, Version 2 (Accession No. ML113080074) identifies the three Census tables as:

B02001 (RACE)
B03003 (HISPANIC OR LATINO ORIGIN)
C17002 (RATIO OF INCOME TO POVERTY LEVEL IN THE PAST 12 MONTHS).

45. The FEIS states that, in determining whether each minority or low-income population should be considered a population of interest, the Environmental Justice analysis considers whether either 1) the demographic group exceeds 50 percent of the total population for the census block group, or 2) the demographic group is 20 percentage points (or more) greater than the same population's percentage in the census block group's state. Why is 20 percent (above the state average) the threshold criterion? Is this a widely used and accepted threshold criterion?

Staff Response: The criteria in question are widely used and accepted for environmental justice (EJ) analyses.

The President issued Executive Order 12898 in February 1994 mandating that Federal agencies make EJ part of each agency's mission by addressing disproportionately high and adverse human health or environmental effects of Federal programs, policies, and activities on minority populations and on low-income populations. No specific guidance was given in the EO as to how such assessments were to be made. NRC's process for assessing EJ was established in March 1994 as part of the NRC's implementation of NEPA—which was consistent with the Council on Environmental Quality's (CEQ's) recommendation for addressing EJ. Following publication of the CEQ's guidelines on how to incorporate environmental justice in the NEPA review process in December 1997, the NRC staff in the Office of Nuclear Reactor Regulation (NRR) developed EJ guidance with the CEQ guidance as the model. See NRR Office Instruction, LIC-203, Rev. 1, "Procedural Guidance for Preparing Environmental Assessments and Considering Environmental Issues" (May 24, 2004) (ADAMS Accession No. ML033550003). The NRR guidance was then incorporated into NUREG-1555, "The Environmental Standard Review Plan for Nuclear Power Plants" (March 31, 2000) (ADAMS Accession No. ML003702134). The CEQ guidance upon which the NRC's guidance was written states:

> "Minority populations should be identified where either: (a) the minority population of the affected area exceeds 50 percent or (b) the minority population percentage of the affected area is meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis."

To avoid ambiguity and to provide consistency across NRC EJ assessments, the NRC staff clarified "meaningfully greater" to mean "20 percentage points or more." The rationale for this percentage is described in ISG-026 "Interim Staff Guidance on Environmental Issues

Associated with New Reactors, Attachment 2: Staff Guidance for the Socioeconomic and Environmental Justice Analysis" (September 2, 2014) (ADAMS Ascension Number ML13350A399). The NRC staff also determined that it was more appropriate to use the study area's state as the "appropriate unit of geographic analysis," rather than the county, because the larger sample area would result in a more conservative (inclusive) set of EJ communities to study.

46. Given that the Office of Nuclear Reactor Regulation (NRR) oversees the compliance and enforcement of NMFS's current Biological Opinion for Crystal River for sea turtles, explain any efforts that the Office of New Reactors (NRO) Staff took to coordinate with NRR Staff concerning up-to-date information on sea turtles and the assessment of potential impacts on sea turtles.

<u>Staff Response</u>: The LNP review team engaged in some discussion with NRR staff regarding potential impacts to sea turtles and characterization of the aquatic environment during and subsequent to the environmental review for the LNP. However, based on the project description (i.e., closed-cycle cooling and compliance with EPA's 316(b) regulations regarding impingement and entrapment), there are likely to be limited impacts to sea turtles as compared to the Crystal River because of the significant differences in the LNP cooling system design. As compared to the once-through cooling system at Crystal River, the proposed LNP closed cycle cooling system would substantially reduce impingement and entrapment of aquatic biota. Moreover, the NMFS concurrence with the NRC staff's Biological Assessment indicates that operation of the LNP would not adversely affect sea turtles.

47. In Section 4.4.3.3, Taxes, it is not clear why the impacts to Levy County are "MODERATE (beneficial)." It seems that the primary driver of the "moderate" impact determination could be the property taxes at the site; however, even after the agricultural tax exemptions expire upon the start of construction, those tax revenues remain a fraction (from $11,000 before construction to $77,000 during) of the County's overall property tax income ($18 million). The FEIS states that once the plant is reassessed after construction is complete, property taxes will increase a significant amount. It appears, however, that this tax income is considered in Chapter 5, Impacts of Operation. Why are taxes considered MODERATE (beneficial) as opposed to SMALL (beneficial) for the construction/pre-construction phase?

<u>Staff Response</u>: The economic impacts and tax impacts are considered separately in the FEIS. Staff did not consider the tax impacts to be MODERATE (beneficial) during the construction phase of the EIS, but rather that they would have a SMALL impact. As stated on pages 4-89 and 4-90:

> "Without the exemption, the increased annual revenue would be $77,259. Against Levy County's annual property tax revenue of $18 million, this would have a <u>minimal effect</u>" (emphasis added).

However, in FEIS Section 4.4.3.1, “Economy,” the staff concluded on page 4-89 that the “increase in employment, earnings, and expenditures within Levy County during peak employment would have a noticeable beneficial effect.” Section 4.4.3.4, “Summary of Economic Impacts on the Community” states:

> “Based upon information provided by PEF in its ER and its own independent analysis, the review team determined that the economic impacts would be MODERATE and beneficial for Levy County and SMALL and beneficial for the rest of the EIA and the region. <u>The review team also determined that the tax impacts from building activities would be SMALL and beneficial for the entire EIA and region</u>” (emphasis added).

48. In Section 4.4.4.3 (and also in Chapter 5) of the FEIS, there is a discussion about housing values in the vicinity of the LNP. The FEIS cites two studies: Bezdek and Wendling (2006) and Clark et al. (1997). Have there been more recent studies of housing values near nuclear power plants that are applicable to this review? If so, were these studies evaluated in the Staff’s consideration of new and significant information?

<u>Staff Response</u>: There are numerous studies that have been performed related to the effects of siting a nuclear power plant on nearby housing values. Bezdek and Wendling (2006) and Clark et al. (1997) were chosen as representative studies from that literature. As part of its new and significant information review process, the Staff remains current on all topics related to the environmental factors that can be affected by the building and operating of a nuclear power plant, including the relevant literature of risk perception and changes in the valuation of property. The Staff has not identified any studies that present conclusions that differ significantly from those in the representative studies in the FEIS.

49. FEIS Sections 5.3.1.4, Terrestrial Monitoring, and 5.3.1.5, Potential Mitigation Measures for Terrestrial Impacts, do not discuss the Reasonable and Prudent Measures or Terms and Conditions contained in the FWS Biological Opinion for Florida scrub-jays. Describe the monitoring and mitigation required by NRC and USACE as a result of the Biological Opinion.

<u>Staff Response</u>: The NRC staff included in the draft EPP (part of the draft COL) conditions to implement the terms and conditions of the ITS issued to the NRC with the BO. To implement these terms and conditions, the EPP will require the applicant to resurvey potentially suitable habitat for the Florida scrub-jay and three other species indicated by the U.S. Fish and Wildlife Service (FWS) no more than two years prior to any ground-disturbing activities, avoid work in potential scrub-jay habitat during the nesting season, notify NRC of any unauthorized taking of a Florida scrub-jay, and implement the FWS, “Standard Protection Measures for the Eastern Indigo Snake.” The license conditions that the NRC will include in the draft EPP implement all of the terms and conditions that FWS intended to include in the ITS issued with the BO to complete consultation under Section 7 of the ESA.

50. Section 5.3.1.6 indicates that the FWS's Biological Opinion requires updated surveys for federally listed species prior to ground disturbances. Will the Staff ensure that these surveys are completed? If so, how will the Staff ensure that these surveys are completed?

As part of the draft COL, the NRC staff included an Environmental Protection Plan with license conditions to implement the terms and conditions set forth in the ITS issued by the FWS with the BO. One of these conditions requires the applicant to perform updated species surveys no more than two years prior to conducting ground-disturbing activities and to coordinate with the FWS on the results of those surveys. Because this survey requirement would be a license condition, the NRC may conduct inspections or audits to verify compliance with the license.

51. In the FEIS, the Staff relied heavily on the U.S. Global Change Research Program's 2009 "Global Climate Change Impacts in the United States" to evaluate impacts of the proposed action on climate change. Did the Staff consider whether updated information in the 2014 "Global Climate Change Impacts on the United States" would change the evaluation or conclusions of the Staff's climate change analysis? If so, please discuss the Staff's considerations. If not, why not?

Staff Response: Climate change information in GCRP 2009 for the LNP site is not significantly different than the climate change information in GCRP 2014, in light of the uncertainty in the predictions. For example, both the 2009 and 2014 reports predict temperature changes by the end of the century to be between 3 degrees Fahrenheit (low emissions scenario) and 8 degrees Fahrenheit (high emissions scenario) for the Levy area. Regarding sea level rise, GCRP 2014 Figure 17.6 shows LNP as being in an area of moderate sea level rise. GCRP 2009 reported a sea level rise of 1-3 feet by 2100 for the Levy Area whereas GCRP 2014 reports a sea level rise of 1-4 feet.

The LNP FEIS statements on climate change are consistent with those made for the region in the GCRP 2014 report. The Staff also determined that differences in climate change projections between the two documents did not warrant changes to the FEIS. The new information contained in the 2014 GCRP report does not meet either of the criteria in 10 CFR 51.92(a) that would require NRC to supplement the FEIS.

52. Table 7-1 of the FEIS lists the past, present, and reasonably foreseeable future projects and other actions considered in the LNP cumulative impacts analysis. In its review of new and potentially significant information, did the Staff consider changes to the projects described in this table and whether those changes would require supplementation of the FEIS? (For instance, a number of the projects are listed as "proposed" but may not have been undertaken or may have been altered

before being implemented, given the amount of time that has passed since completion of the FEIS.) If not, why not?

<u>Staff Response</u>: Yes, as part of its review of new and potentially significant information, the Staff did consider changes to projects listed in Table 7-1, including new projects and proposed projects that may have been cancelled or altered. The Staff has not identified any developments that would warrant a supplement to the LNP COL FEIS.

53. Discuss how the Staff in the LNP environmental review tailored its discussion of "other alternatives" based on the location of the proposed plant.

<u>Staff Response</u>: The Staff develops its analysis of energy alternatives based on those alternatives that are available at or in the region of the proposed action. The Staff reviewed various documents to develop its analyses, including documents from the Department of Energy (see, for example, Section 9.2.3.2, page 9-21) and from the State of Florida (see Section 9.2.3, page 9-20). So, for example, the poor potential for wind generation in Florida was part of the basis for rejecting wind energy as a feasible alternative. Likewise, the Staff found that Florida does not have geothermal resources suitable for baseload power generation.

54. In considering whether new information would require supplementing the FEIS, did the Staff consider changes in State regulations, energy conservation objectives, and greenhouse gas emission reduction goals, etc.? Why or why not?

<u>Staff Response</u>: Since the 2012 publication of the FEIS, the Staff evaluated how recent developments (such as changes in regulations and energy conservation objectives) may have affected its analysis of energy alternatives and concluded that the changes did not warrant a supplement to the FEIS. For this evaluation, the Staff drew from three primary sources: the DEF, Ten-Year Site Plan (TYSP), submitted by DEF to the Florida Public Service Commission on April 1, 2015; and the data developed by the U.S. Department of Energy, Energy Information Administration (DOE/EIA), as presented in its Annual Energy Outlook (AEO) 2015, which was released on April 14, 2015, and the Florida Electricity Profile 2013, released July 8, 2015. The last document is simply based on past data collected by DOE/EIA. The first two documents include projections based on the best available information regarding current and future changes in regulations and generating technologies. As such, the types of changes discussed in the question are built into the Staff's evaluation.

55. Please summarize the key U.S. Environmental Protection Agency's comments on the draft EIS and how the Staff addressed those in the FEIS.

<u>Staff Response</u>: Although the Environmental Protection Agency (EPA) commented on several environmental issues in its comment letter on the DEIS dated October 26, 2010 (ADAMS Accession No. ML103080058), its environmental comments focused primarily on wetland impacts and efforts to avoid and minimize those impacts. EPA states that "impacts to wetlands is a primary concern that needs to be further addressed" and that there may be a need for “changes to the current site layout or application of mitigation measures that could reduce the environmental impacts.”

The response to the above comment in Appendix E of the FEIS notes that “the NRC and USACE worked with the EPA to identify further reductions of such [wetland] impacts, and these have been incorporated into Section 4.3.1 of the EIS” (FEIS, Appendix E, p. E-84). The responses to other wetland-related comments in the EPA letter (FEIS, Appendix E, pp. E-84 to E-86) describe how the applicant re-routed a pipeline to reduce wetland impacts, including avoidance of approximately 4.5 acres of high value salt marsh wetlands and how the applicant responded to USACE requests to minimize wetland impacts via a “position letter” in 2011. The NRC staff updated the information in the DEIS to reflect numerous changes proposed by the applicant to the site layout that reduced wetland impacts. The NRC staff also updated the information in the DEIS to reflect a jurisdictional determination received by the applicant from USACE and to reflect a detailed wetland mitigation plan based on functional units under the State of Florida’s Unified Mitigation Assessment Method. Although the FEIS actually reported somewhat greater wetland impacts on the LNP site (approximately 450 acres versus approximately 403 acres in the DEIS), this reflected the fact that the FEIS used more accurate wetland delineation data from the USACE jurisdictional determination, whereas the DEIS used land cover mapping data.

None of the EPA comments resulted in the NRC staff needing to change conclusions in the FEIS or the direction and scope of its analyses. The NRC staff did, however, include updated site design and layout information in the FEIS.

56. The NMFS separated the listing of the loggerhead sea turtle into distinct population segments in September 2011 (nearly 8 months before NRC published the FEIS) (76 Fed. Reg. 58,868), but the biological assessment does not address the species by distinct population segments (see page F-87). This could affect the NRC’s conclusions because the FEIS’s analysis of effects to the species is considered in light of the size of the global population of loggerheads instead of in light of the size of the distinct population segment that would occur near LNP. Did the NRC Staff consider whether this listing would constitute new and significant information? If so, what were the results? If not, why not?

<u>Staff Response</u>: The Staff was aware that the NMFS determined that the worldwide distribution of loggerhead sea turtles (*Caretta caretta*) is composed of nine distinct population segments (DPS). The rulemaking establishing these DPS was effective on October 24, 2011. The loggerhead sea turtles found in Crystal Bay are part of the Northwest Atlantic Ocean DPS stretching from the mid-Atlantic north to the tip of Greenland, south to Brazil and west to include the Gulf of Mexico. The Staff used the Crystal River annual sea turtle reports as one source of information to characterize the aquatic resources in the vicinity of Crystal Bay, particularly with regard to distribution, relative abundance and life history information. The absolute values of captures or mortalities at Crystal River and its potential impact on the Northwest Atlantic Ocean DPS was of little value in assessing impact to the population from the operation of the LNP.

Due to the reduced intake flow associated with the closed-cycle cooling system proposed for LNP and the limitation of the through screen velocity of the intake to 0.5 fps or less, the review team concludes that sea turtle strandings, including loggerheads, on the LNP intake trash bars is unlikely and would be limited to moribund or compromised individuals. The NMFS concurred on the Staff's impact conclusions during consultation under ESA.

57. The correspondence between the NRC Staff, the USACE, and NMFS in Appendix F seems to indicate that the essential fish habitat (EFH) consultation under the Magnuson-Stevens Act (MSA) was not completed at the time the Staff issued the FEIS. Has this consultation been concluded following the publication of the FEIS? If not, when will it be concluded and how will it be documented? If so, what were the results of the consultation?

Staff Response: Yes, the EFH consultation has been concluded and is documented in a letter (ADAMS Accession No. ML12097A166) dated April, 4, 2012, to Col A. Pantano, USACE from V. Fay, NMFS. The letter states that all five NMFS EFH conservation recommendations were adequately addressed and that consultation under the provisions of 50 CFR Section 600.920 of the regulation to implement the EFH provisions of the MSA has been completed for the LNP. As such, no further EFH consultation is needed.

58. Has the Staff kept track of updates to Appendix H Authorizations, Permits, and Certifications since the 2012 publication of the FEIS?

Staff Response: Yes, the Staff requested that the applicant keep NRC informed of any updates to authorizations, permits and certifications listed in Appendix H of the FEIS. Subsequent to the publication of the FEIS in 2012, the applicant has sent two updates to items listed in Appendix H. Specifically, the "Levy Nuclear Plant and Associated Transmission Lines Wetland Mitigation Plan Comprehensive Design Document – September 2015" was submitted to NRC on October 19, 2015 (ADAMS Accession No. ML15294A205). On January 7, 2016, the applicant provided NRC with the Department of the Army Permit (Section 404 Permit) for the Levy Nuclear Project (ADAMS Accession No. ML16008A083), which incorporated and codified the aforementioned wetland mitigation plan.

59. Please explain (without using deliberative or privileged information) the nature of the two non-concurrences and how they were resolved. Include in this discussion any previous generic analysis of ISFSI impacts that may apply to the LNP environmental review, and opportunities for public involvement involved in those analyses.

Staff Response: In the course of the Staff's environmental review, two related non-concurrences were filed: one on SECY-16-0076, "Staff Statement in Support of the Uncontested Hearing for Issuance of Combined Licenses for the LNP Units 1 and 2," and another on the memorandum documenting the completion of the Staff's review of new and significant environmental information. Both non-concurrences raised questions as to whether additional steps under NEPA of 1969, as amended, National Historic Preservation Act (NHPA) of 1966, as amended, and ESA of 1973, as amended, were warranted in light of the regulation in 10 CFR 72.210, which grants a general license to construct and operate an independent spent fuel storage installation (ISFSI) to certain licensees, including COL holders, if certain conditions are met. Following deliberations about the concerns of the non-concurring staff and potential options to address them, the non-concurrences were resolved, and the non-concurring staff ultimately concurred on these documents.

In reviewing the non-concurrences, Staff management followed the non-concurrence procedures set out in Management Directive 10.158. Based on this process, the direct supervisor of the non-concurring staff members reviewed the issues raised and determined that he did not agree with the conclusions of the non-concurring staff. Additionally, a senior manager in the Office of New Reactors was designated as the Non-Concurrence Process Approver to review the non-concurrence and supervisor review comments and make a final determination. The Approver also disagreed with the conclusions of the non-concurring staff that additional steps under NEPA, NHPA, and ESA were necessary. The Approver found this conclusion to be supported by the environmental analyses provided and referenced in the LNP FEIS and the 10 CFR 72.210 rulemaking record, both of which were subject to public review and comment; the consultation records; and the EPP.

Although Staff management concluded that additional actions were not required to meet NRC's statutory responsibilities, Staff management and the non-concurring staff agreed to an additional outreach step, which the non-concurring staff agreed resolved their concerns.

60. Explain whether the Staff's environmental review takes into account all impacts of an ISFSI on the site (including, for example, land use impacts associated with use of the site after plant shutdown).

Staff Response: In the FEIS, the Staff incorporated by reference the analysis in the Generic Environmental Impact Statement (GEIS) for License Renewal (NUREG-1437) regarding the impacts of onsite storage of spent nuclear fuel in an ISFSI. As part of the Staff's review of new and potentially significant information, the Staff evaluated information from the Continued Storage GEIS (NUREG-2157) regarding impacts of onsite storage of spent nuclear fuel in an ISFSI after licensed life. These environmental analyses both supported the Staff conclusion that fuel cycle impacts for the LNP COL would be SMALL.

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

Staff Response: In its August 18, 2015, analysis of this new information for the Levy COL (ADAMS Accession No. ML15176A345), the Staff did consider the environmental impacts of spent fuel storage and concluded that the new information in NUREG-2157, "does not present a seriously different picture of the environmental impacts of the proposed action when compared to the impacts that were described in the FEIS for LNP Units 1 and 2." Since the new information did not change in a meaningful way the Staff's conclusions regarding fuel cycle impacts for the project, there was no need to modify or reconsider the Staff's previous evaluation of alternatives or the cost-benefit balancing that had been performed in the Levy FEIS. There were no changes needed to these FEIS analyses based on the Staff's August 18, 2015, analysis.

62. Please provide additional summary information on the costs of refurbishment and environmental impacts of operating refurbished coal-fired units.

<u>Staff Response</u>: Refurbishment (upgrading) is the process of replacing older, less efficient components on an existing (older) boiler to extend its useful life, provide greater (or more reliable) generating capacity, reduce emissions, and avoid the cost of retiring the older unit and replacing it with a newer one. In addition, under the Clean Air Act, a coal plant upon which significant modifications have been made is required to meet current (i.e., more restrictive) emissions requirements. Upgrading cannot be universally applied, and is subject to physical, structural, and design limitations, all of which involve significant costs. Retrofitting an existing unit to incorporate mandated air pollution control (APC) devices costs more than the same devices installed during the construction of a new unit, and the parasitic power demand for retrofitted APCs is typically greater than the requirements for a new unit. This is because the retrofitting of any device necessarily requires some degree of extra ducting and piping, which reduces flow rates and hinders the device's designed performance. Additionally, retrofitting to add APCs or to improve boiler performance provides less improvement (in terms of additional generating capacity, improved pollution control, etc.) than a new unit.

The result is that while upgrading a boiler may cost less than replacing the boiler with a new one, the upgraded boiler will operate less efficiently than a new boiler and will have greater pollution emissions and higher operating costs. In effect, the upgraded boiler is environmentally inferior to a new boiler. The Staff compared the environmental impacts of a new coal plant to the proposed nuclear plant as a part of the alternative energy discussion in Section 9.2.5 of the FEIS and concluded it was not environmentally preferable. Therefore, a refurbished coal plant would also not be environmentally preferable to the proposed action.

63. Does comparing the cumulative impacts of the proposed action with the non-cumulative impacts of the generation alternatives in Table 9-4 yield a more conservative analysis than comparing the noncumulative impacts of the proposed action with the noncumulative impacts of the generation alternatives?

<u>Staff Response</u>: Comparing the cumulative impacts of the proposed action with the non-cumulative impacts of the generation alternatives could yield inappropriate results. A proposed project that, by itself, would have SMALL impacts in all resource areas could be penalized by significant cumulative impacts from other (unrelated) actions, while the alternatives would not include cumulative impacts. To avoid potentially reaching an inappropriate conclusion, the Staff would either have to use cumulative impacts for both the proposed action and alternative energy sources, or use it for neither. The Staff has chosen the latter course of action because some portions of the combination of energy alternatives (e.g., solar) would be built at an unknown location, which makes it impossible to develop cumulative impacts.

64. Why are the cumulative impacts on surface water MODERATE for the Dixie site alternative when the FEIS concludes that other projects listed in Table 9-13 have little or no impact on surface water and building and operating a plant at the Dixie site would not be a significant contributor to those impacts?

Staff Response: There is a minor error in the FEIS in that the MODERATE impact as described on 9-110 should have been attributed to the operation of a plant at the site. As explained on page 9-108, operations of the proposed plant would increase use of the Suwannee River, which has already experienced recent extended periods when minimum flow targets set by the Suwannee River Water Management District have not been met. As a result, the review team determined that any increased water usage would be "noticeable but not destabilizing" (page 9-108). This is consistent with the definition of MODERATE provided in Table B-1 of 10 CFR Part 51, Subpart A, Appendix B.

65. Clarify whether the Highlands site requires 6,725 (9-151) or 2,000 acres (9-161) for the transmission line corridor and whether the Putnam site requires 6,212 (9-196) or 2,150 acres (9-206) for the transmission line corridor.

Staff Response: For Highlands, as noted in footnote (a) to Table 9-21, the 6,725 acres refers to the entire transmission line corridor. The 2000 acre number refers only to land areas requiring ground disturbance to build the transmission lines. For example, in open areas such as crop lands and pastures ground disturbance may be limited to tower pads and access roads. The same explanation applies to the Putnam site.

66. What additional actions would the applicant need to take to acquire water rights to the Kissimmee River for the Highlands site alternative since "no additional surface water will be allocated from [South Florida Water Management District]-controlled surface-water bodies over and above existing allocations?"

Staff Response: The Staff cannot speculate on the specific actions that would be taken to obtain water for the Highlands site if it were used. But in accordance with NRC guidance in the ESRP, there should be reasonable assurance that water could be obtained. If the Highlands site were to be used, one option for the applicant would be to obtain water rights currently held by others. Another option would be to obtain permits to use groundwater, or some combination of surface water and groundwater.

In its review of the COL application for the Turkey Point site, the Staff reviewed the Okeechobee 2 alternative site, located a few miles from the Highlands site. As discussed in the DEIS for the Turkey Point COL application (NUREG-2176), based on discussions with the South Florida

Water Management District it could be possible to obtain sufficient water for the Okeechobee 2 site. See Sections 9.3.1.7 and 9.3.4.2 in NUREG-2176. A similar approach could be implemented at the Highlands site.

67. Please explain the justification for assuming subsistence fishing for the Putnam site but not the Crystal River or Dixie sites.

Staff Response: The differences in the presence (or lack) of subsistence fishing in all four alternative site EJ analyses was based upon reconnaissance level investigation, followed up with Staff contact with local officials in the host county for each alternative site.

- The Crystal River site, because of its proximity to the proposed LNP site, was considered to have the same EJ impacts as the LNP site, with "no evidence of unique characteristics or practices" (p. 9-89). The Crystal River site was therefore assumed to have no subsistence fishing activity.
- Staff contacted the Dixie County Environmental Health Division (DCEHD) and was informed the DCEHD was not aware of any subsistence use of resources in the county (p. 9-138). The Dixie site was therefore assumed to have no subsistence activity.
- For the Highlands alternative site, the FEIS at page 9-182 states "personnel from the County Natural Resources Department noted that perhaps 1 percent of the county population may engage in subsistence fishing." Therefore, the Staff assumed the presence of subsistence fishing in its EJ analysis of the Highlands site.
- For Putnam, the Staff was not able to contact a local government agency and performed its own investigation based on a visit to the area. As discussed in the FEIS: "the review team investigated the presence of unique characteristics or practices in minority or low-income communities that would result in different socioeconomic impacts from the Putnam site compared to the general population and found one unique characteristic that could lead to disproportionate impacts: reliance on subsistence" (p. 9-227).

68. The FEIS estimates that the Dixie site would disturb approximately 5,468 acres of land (9-103), the Highlands site would disturb about 4,068 acres of land (9-151), and the Putnam site would disturb around 4,218 acres of land but that the Levy site would only disturb roughly 2,525 acres of land (4-17). Nonetheless, Table 9-31 lists the cumulative impacts for land use at all of these sites as MODERATE. Does the significant difference in disturbed land between the LNP site and these alternative sites provide further support for the Staff's conclusion that none of the alternative sites are environmentally preferable to the proposed LNP site? (9-243)

Staff Response: SMALL, MODERATE, and LARGE land use impact conclusions reflect more than the spatial extent of project activities. For example, the land use review also includes consideration of zoning, compatibility with nearby land uses, and the presence of absence or land use constraints and opportunities. Accordingly, the inclusion of land use acreages in the Staff's analyses was not intended to indicate that the acreages were the only environmentally significant factors in differentiating land use impacts among the sites in the FEIS. Instead, the table indicates that the land use impacts at each of the sites would be MODERATE, defined in 10 CFR 51, Subpart A, Appendix B as "sufficient to alter noticeably, but not to destabilize, important attributes of the resource." The land use information presented in Sections 4.1 and 9.3 of the FEIS indicates that the land use impacts from building a nuclear power plant at each of the sites would be noticeable but unlikely to destabilize land resources important to local and regional planning processes. The purpose of Section 9.3, including Table 9-31, is to indicate whether any alternative site is both "environmentally preferable" and "obviously superior" to the proposed LNP site. The same conclusions of MODERATE for each site considered in Table 9-31 indicate that the differences in land use impacts among the sites are not great enough to contribute to a determination that any of the sites are "obviously superior" to the others.

69. Have there been significant energy or environmental regulatory or policy changes at the state or federal level that alter the viability of the various alternatives evaluated in the FEIS?

Staff Response: With respect to energy alternatives, as discussed in the response to Question 54, the Staff reviewed more recent information in documents from the applicant and the DOE/EIA in its March 29, 2016, evaluation of new information related to energy alternatives (ADAMS Accession No. ML16060A190) and concluded that recent changes did not warrant a supplement to the FEIS. The documents the Staff reviewed took into account the most recent information related to regulatory and policy changes affecting the alternatives, thus informing the Staff's evaluation. For example, recent EPA regulations commonly referred to as the "Clean Power Plan" make it unlikely that a new coal-fired power plant would be built. However, such a plant is not prohibited. In the Levy FEIS the Staff concluded that a new coal-fired power plant would not be environmentally preferable to the proposed action. As such, any regulatory change that reduces the likelihood of a new coal-fired power plant would not change the Staff's conclusions.

The Staff identified no changes that would impact the viability of alternative sites or alternative system designs.

70. One of the reasons that the applicant provided for selecting the Levy 2 area as its proposed site instead of the Crystal River site was that adding new nuclear generating capacity at Crystal River would result in a significant concentration of the applicant's generating assets in one location. According to the applicant, this would make its system overly vulnerable to a major hurricane or other natural or man-made disaster. Further, in its Section 404(b)(1) Alternatives Analysis the applicant concluded that the Crystal River site would not meet the purpose and need of the project. Has the decision not to restart Crystal River Unit 3 changed this analysis? Has this decision affected the USACE's determination of the LEDPA?

Response to be submitted by the applicant only.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

In the Matter of	)	
	)	
DUKE ENERGY FLORIDA, LLC	)	Docket Nos. 52-029 and 52-030
	)	
(Levy Nuclear Plant, Units 1 and 2)	)	

CERTIFICATE OF SERVICE

I hereby certify that the document entitled NRC STAFF RESPONSES TO COMMISSION PRE-HEARING QUESTIONS, dated July 7, 2016, has been filed through the E-Filing system this 7th day of July, 2016.

/Signed (electronically) by/
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Dated at Jersey City, New Jersey,
this 7th day of July 2016