UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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ATLANTA, GEORGIA 30303-1257

July 27, 2018

Mr. Mano Nazar
President and Chief Nuclear Officer
Nuclear Division
Florida Power & Light Company
Mail Stop: EX/JB
700 Universe Blvd.
Juno Beach, FL 33408

SUBJECT: ST. LUCIE PLANT – NUCLEAR REGULATORY COMMISSION INTEGRATED INSPECTION REPORT 05000335/2018002 AND 05000389/2018002

Dear Mr. Nazar:

On June 30, 2018, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your St. Lucie Plant Units 1 and 2. On July 12, 2018, the NRC inspectors discussed the results of this inspection with Mr. DeBoer and other members of your staff. The results of this inspection are documented in the enclosed report.

The NRC inspectors did not identify any finding or violation of more than minor significance.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and at the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Randall A. Musser, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket Nos.: 50-335, 50-389
License Nos.: DPR-67, NPF-16

Enclosures:
1. IR 05000335/2018002 and 05000389/2018002
2. Temporary Instruction 2515/194 Inspection Results
3. Table 1 – Information Gathered for TI 2515/194
4. Documents Reviewed

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-335, 50-389
License Nos:	DPR-67, NPF-16
Report Nos:	05000335/2018002, 05000389/2018002
Enterprise Identifier:	I-2018-002-0040
Licensee:	Florida Power & Light Company (FPL)
Facility:	St. Lucie Plant, Units 1 and 2
Location:	6501 South Ocean Drive Jensen Beach, FL 34957
Dates:	April 1, 2018 through June 30, 2018
Inspectors:	T. Morrissey, Senior Resident Inspector S. Roberts, Resident Inspector G. Crespo, Senior Construction Inspector (TI-194) D. Terry-Ward, Construction Inspector (TI-194)
Accompanying Personnel:	K. Nguyen, Electrical Engineer, NRR/DE/EEOB (TI-194)
Approved by:	R. Musser, Chief Reactor Projects Branch 3 Division of Reactor Projects

SUMMARY

The U.S. Nuclear Regulatory Commission (NRC) continued monitoring licensee's performance by conducting a baseline inspection in addition to Temporary Instruction 2515/194, "Inspection of the Licensee's Implementation of Industry Initiative Associated with the Open Phase Condition Design Vulnerabilities in Electric Power Systems (NRC Bulletin 2012-01)," at St. Lucie Plant Units 1 and 2 in accordance with the Reactor Oversight Process. The Reactor Oversight Process is the NRC's program for overseeing the safe operation of commercial nuclear power reactors. Refer to https://www.nrc.gov/reactors/operating/oversight.html for more information.

List of Findings and Violations

No findings were identified

Additional Tracking Items

Type	Tracking number	Title	Report Section	Status
Temporary Instruction (TI)	2515/194	Inspection of the Licensee's Implementation of Industry Initiative Associated with the Open Phase Condition Design Vulnerabilities in Electric Power Systems (NRC Bulletin 2012-01)	Other Activities	Complete

PLANT STATUS

Unit 1 began the inspection period shut down in Mode 6 in a refueling outage. Following the outage, on April 11, 2018, the control room operators commenced a reactor startup and the reactor reached 100 percent rated thermal power (RTP) on April 13, 2018. The unit was at or near 100 percent RTP for the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent RTP. On May 3, 2018, Unit 2 reduced power to 83 percent RTP to support a planned maintenance evolution. Unit 2 returned to 100 percent RTP power on May 4, 2018, and remained at or near 100 percent RTP for the remainder of the inspection period.

INSPECTION SCOPES

Inspections were conducted using the appropriate portions of the inspection procedures (IPs) in effect at the beginning of the inspection unless otherwise noted. Currently approved IPs with their attached revision histories are located on the public website at http://www.nrc.gov/reading-rm/doc-collections/insp-manual/inspection-procedure/index.html. Samples were declared complete when the IP requirements most appropriate to the inspection activity were met consistent with Inspection Manual Chapter (IMC) 2515, "Light-Water Reactor Inspection Program - Operations Phase." The inspectors performed plant status activities described in IMC 2515 Appendix D, "Plant Status" and conducted routine reviews using IP 71152, "Problem Identification and Resolution." The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel to assess licensee performance and compliance with Commission rules and regulations, license conditions, site procedures, and standards."

REACTOR SAFETY

71111.01 - Adverse Weather Protection

Summer Readiness (1 Sample)

The inspectors evaluated and completed the licensee's summer readiness of offsite and alternate alternating current (AC) power systems on May 31, 2018.

Seasonal Extreme Weather (1 Sample)

The inspectors evaluated and completed the licensee's readiness for seasonal extreme weather conditions prior to the onset of hurricane season on May 31, 2018.

External Flooding (1 Sample)

The inspectors evaluated and completed the licensee's readiness to cope with external flooding on May 31, 2018.

71111.04 - Equipment Alignment

Partial Walkdown (4 Samples)

The inspectors evaluated system configurations during partial walkdowns of the following systems/trains:

(1) Unit 2, 2B low pressure safety injection (LPSI) train with 2A LPSI train out of service (OOS) for planned maintenance on April 18, 2018
(2) Unit 1, 1A component cooling water (CCW) train while 1B CCW heat exchanger (HX) was OOS for planned maintenance on April 25, 2018
(3) Unit 1, 1B emergency diesel generator (EDG) while 1A EDG was OOS for planned maintenance on May 13, 2018
(4) Unit 1, 1A and 1C auxiliary feedwater (AFW) trains while 1B EDG was OOS for planned maintenance on June 19, 2018

Complete Walkdown (1 Sample)

The inspectors evaluated system configurations during a complete walkdown of the 2A LPSI train on June 4, 2018.

71111.05AQ - Fire Protection Annual/Quarterly

Quarterly Inspection (6 Samples)

The inspectors evaluated fire protection program implementation in the following selected areas:

(1) Unit 1, reactor auxiliary building -0.5 foot elevation on April 4, 2018
(2) Unit 2, 2A3 vital switchgear room on April 17, 2018
(3) Unit 1, 1B EDG room on May 16, 2018
(4) Unit 2, A and B vital battery rooms on June 1, 2018
(5) Unit 1, 1A and 1C AFW pump areas on June 19, 2018
(6) Unit 2, 2B high pressure safety injection (HPSI), containment spray room on June 27, 2018

71111.06 - Flood Protection Measures

Underground Manhole (MH) Inspections (5 Samples)

(1) Unit 2, MH 213 containing safety-related cables associated with the Unit 2 intake cooling water (ICW) system on April 23, 2018
(2) Unit 2, MH 214 containing safety-related cables associated with the Unit 2 ICW system on April 23, 2018
(3) Unit 2, MH 176 containing safety-related cables associated with the Unit 2, 2A and 2B EDG systems on April 26, 2018
(4) Unit 2, MH 177 containing safety-related cables associated with the Unit 2, 2A and 2B EDG systems on April 26, 2018
(5) Unit 2, MH 178 containing safety-related cables associated with the Unit 2, 2A and 2B EDG systems on April 26, 2018

71111.11 - Licensed Operator Requalification Program and Licensed Operator Performance

Operator Requalification (1 Sample)

On May 7, 2018, the inspectors observed and evaluated a licensed operator crew during an evaluated emergency plan evaluation on the control room simulator. The simulated scenario included a loss of offsite power and a station blackout condition. The station blackout condition resulted in a Site Area Emergency classification which required a notification to the State of Florida and the NRC.

Operator Performance (2 Samples)

(1) The inspectors observed and evaluated Unit 1 operator performance during unit startup and power ascension after a planned refueling outage on April 12, 2018
(2) The inspectors observed and evaluated Unit 2 operator performance when reducing power to support planned turbine valve testing on May 13, 2018

71111.12 - Maintenance Effectiveness

Routine Maintenance Effectiveness (1 Sample)

The inspectors evaluated the effectiveness of routine maintenance activities associated with the following equipment and/or safety-significant function:

Unit 2, action request (AR) 2254925, RIM-26-38 (‘A’ post-loss of coolant accident (LOCA) alarm) spiked high then failed low.

Quality Control (1 Sample)

The inspectors evaluated the effectiveness of routine maintenance and reviewed quality control activities associated with the following safety-significant system:

Unit 1 ICW system. Maintenance work order (WO) packages reviewed include WO’s 40592067 and 40503315.

71111.13 - Maintenance Risk Assessments and Emergent Work Control (6 Samples)

The inspectors evaluated the risk assessments for the following planned and emergent work activities:

(1) Unit 1, yellow shutdown safety assessment with reactor coolant system (RCS) level in a lowered inventory condition in order to install the reactor vessel head on April 3-4, 2018
(2) Unit 1, elevated risk when 1B CCW HX was OOS for planned maintenance on April 24, 2018
(3) Unit 1, elevated risk while 1A EDG was OOS for planned maintenance on May 7-14, 2018
(4) Unit 1 and 2, elevated risk while 1B and 2B startup transformers (SUTs) were out of service for planned maintenance on May 30 - June 1, 2018
(5) Unit 1, elevated risk while 1A and 2A SUTs, 1A LPSI pump, 1A EDG, were OOS for planned maintenance on June 18, 2018
(6) Unit 1, elevated risk while 1B EDG was OOS for planned maintenance on June 18-25, 2018

71111.15 - Operability Determinations and Functionality Assessments (6 Samples)

The inspectors evaluated the following operability determinations and functionality assessments:

(1) Unit 2, AR 2257952, degraded bolts on the 2A EDG diesel oil storage tank, on April 16, 2018
(2) Unit 2, AR 2261698, invalid diagnostic test results for Unit 2 HCV-2646 (motor operated valve for HPSI injection to RCS loop 2B2), on April 30, 2018
(3) Unit 1, AR 2264531, failure indication of under voltage (UV) relays 27-1 and 27-2 while performing 1-OSP-52.01A, "Surveillance Test of Degraded Grid A Train," on May 16, 2018
(4) Unit 1, AR 2265588, post-accident instrument solenoid isolation valves incorrectly wired
(5) Unit 2, AR 2267796, vibration more than expected on the main steam pipe to 2C AFW
(6) Unit 2, AR 2269268, degraded seismic support down stream of steam generator atmospheric dump valve MV-08-18A

71111.18 - Plant Modifications (2 Samples)

The inspectors evaluated the following temporary or permanent modifications:

(1) Engineering change (EC) 287460, "Replacement of Rosemount Transmitter for SG 1B, PT-8023A, C and D," on April 2, 2018
(2) EC 291305, "Containment Pressure Transmitter (PT-07-8B) Sensing Line Modification," on May 25, 2018

71111.19 - Post Maintenance Testing (5 Samples)

The inspectors evaluated the following post-maintenance tests:

(1) Unit 1, 1-OSP-07.02A, "1A Containment Spray Pump Safeguards Full Flow Test," after replacing 1A containment spray pump motor in accordance with WO 40176943 on April 2, 2018
(2) Unit 2, 2-NOP-02.02, "Charging and Letdown," following maintenance on the 2C charging pump accumulator, under WO 40549170, on April 10, 2018
(3) Unit 1, 1-OSP-59.01A, "1A Emergency Diesel Generator Monthly Surveillance," following planned maintenance under WO 40590080, on May 14, 2018
(4) Unit 1, WO 40604947, repair HCV-21-7B, 1B CCW HX debris filter system isolation valve, on May 31, 2018
(5) Unit 1, 1-OSP-59.01B, "1B Emergency Diesel Generator Monthly Surveillance," following planned maintenance under WO 40453663, on June 25, 2018

71111.20 - Refueling and Other Outage Activities (1 Sample)

The inspectors evaluated Unit 1 refueling outage (SL1-28) activities from April 1, 2018, until the unit was started up on April 11, 2018. The inspectors completed inspection procedure Sections 03.01.a, 03.01.b, and 03.01.c in the prior inspection period documented in NRC Integrated Inspection report 05000335/2018001 and 05000389/2018001 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML18121A344). The remaining applicable inspection sections for this IP were completed during this inspection period.

71111.22 - Surveillance Testing

The inspectors evaluated the following surveillance tests:

Routine (5 Samples)

(1) Unit 1, 1-OSP.69.14B, “ESF – 18 Month Surveillance For EDG Start On SIAS Without Loop And 24-Hour Load Run – Train B,” on April 2, 2018
(2) Unit 1, 1-OSP-66.03, “CEA Drop Time And Position Indication Functional Tests,” on April 9, 2018
(3) Unit 1, 1-OSP-64.03, “Wide Range Nuclear Instrument Channel Functional Test,” on April 11, 2018
(4) Unit 1, 1-PTP-81, “Reload Startup Physics Testing,” on April 11-12, 2018
(5) Unit 1 and 2, 0-OSP-27.01 “Emergency Cooling Water Canal – Periodic Test,” on April 17, 2018

Reactor Coolant System Leak Detection (1 Sample)

Unit 1, 1-OSP-01.03, “Reactor Coolant System Inventory Balance,” on April 17, 2018

71114.06 - Drill Evaluation

Emergency Planning Drill (1 Sample)

The inspectors evaluated an emergency response drill that included an earthquake, a loss of offsite power, a station blackout, and a LOCA on June 7, 2018.

OTHER ACTIVITIES – BASELINE

71151 - Performance Indicator Verification (4 Samples)

The inspectors verified the following licensee performance indicators submittals for the periods listed below.

(1) Unit 1, RCS activity from April 1, 2017, through March 31, 2018
(2) Unit 2, RCS activity from April 1, 2017, through March 31, 2018
(3) Unit 1, RCS leakage from April 1, 2017, through March 31, 2018
(4) Unit 2, RCS leakage from April 1, 2017, through March 31, 2018

71152 - Problem Identification and Resolution

Semiannual Trend Review (1 Sample)

The inspectors reviewed the licensee’s corrective action program for trends that might be indicative of a more significant safety issue.

Annual Follow-up of Selected Issues (2 Samples)

The inspectors reviewed the licensee’s implementation of its corrective action program related to the following issues. The issues were selected due to their repetitive nature.

(1) HCV-21-7B, 1B CCW HX debris filter system flush valve, limit switch problems (AR's 2266060 and 2266847), which detailed actions taken to address losing valve position indication in the control room for this valve that gets an safety injection (SI) signal to close. The set of valve limit switches were replaced.
(2) 1A charging pump reduced flow (AR's 1755426 and 2266741), which detailed actions taken to address less than normal flow observed from the 1A and 1C charging pumps, due to gas accumulation within the pump.

OTHER ACTIVITIES – TEMPORARY INSTRUCTIONS, INFREQUENT AND ABNORMAL

<u>Temporary Instruction 2515/194 - Inspection of the Licensee's Implementation of Industry Initiative Associated With the Open Phase Condition Design Vulnerabilities In Electric Power Systems (NRC Bulletin 2012-01)</u>

This inspection was conducted using Temporary Instruction 2515/194 (ADAMS Accession No. ML17137A416), dated October 31, 2017. The team reviewed the licensee's implementation of Nuclear Energy Institute (NEI) Voluntary Industry Initiative (VII) in compliance with Commission guidance. The team discussed the licensee's open phase condition system design and ongoing implementation plans with plant staff and vendor staff. The team reviewed licensee and vendor documentation, and performed system walkdowns to verify that the installed equipment was supported by the design documentation. The team verified that the licensee had completed the installation and testing of equipment (with the exception of the tripping functions), installed and tested alarming circuits at the Open Phase Detection and Protection system panel and was in the process of integrating the alarm function with the control room alarm windows, and analyzed potential impacts associated with the design implementation on the plant's current licensing basis.

See Enclosures 2 and 3 for complete documentation of the completion of TI-194.

INSPECTION RESULTS

Observations: Trend Review	71152
The inspectors as well as the licensee identified a negative trend associated with foreign material controls during the Unit 1 refueling outage. Foreign material was identified in the the reactor containment building as well as areas in the switchgear rooms and auxiliary feed water pump areas. The negative trend and associated corrective actions were documented in the CAP as AR 2256969.	

EXIT MEETINGS AND DEBRIEFS

The inspectors verified no proprietary information was retained or documented in this report.

The inspectors confirmed that proprietary information was controlled to protect from public disclosure.

On June 15, 2018, the team presented the Temporary Instruction 2515/194 inspection results to Mr. DeBoer, St. Lucie Site Director and other members of the licensee staff. The team verified no proprietary information was retained; however, some material used by the team to document compliance was characterized as proprietary by the vendor.

On July 12, 2018, the inspectors presented the quarterly resident inspector inspection results to Mr. DeBoer and other members of the licensee staff.

THIRD PARTY REVIEWS

The inspectors reviewed the St. Lucie Institute of Nuclear Power Operations (INPO) plant evaluation report for the evaluation that was completed on December 8, 2017.

Temporary Instruction 2515/194 - Inspection of the Licensee's Implementation of Industry Initiative Associated with the Open Phase Condition Design Vulnerabilities in Electric Power Systems (NRC BULLETIN 2012-01)

The objective of Temporary Instruction 2515/194, was to verify that licensees have appropriately implemented the NEI VII including updating their licensing basis to reflect the need to protect against open phase conditions, and to gather the information necessary for Office of Nuclear Reactor Regulation staff to determine whether the licensees have adequately addressed potential open phase conditions.

Temporary Instruction 2515/194-03.01 - Voluntary Industry Initiative (Part 1)

St. Lucie Plant Units 1 and 2 selected General Electric Energy Connections - ALSTOM, as the design vendor for their open phase detection system. At the end of this inspection the open phase detection and protection (OPDP) system was still in the "monitoring mode" of operation to facilitate continued data gathering of grid perturbations for evaluation of alarm and trip setpoints. The open phase condition equipment was installed on the startup transformers (SUTs) SUT-1A, SUT-1B, SUT-2A, and SUT-2B which provide power to station busses, including the station's four engineered safety feature (ESF) busses. The licensee was scheduled to transition the OPDP system to full implementation (alarm in control room integration and tripping functions enabled) later this calendar year. The licensee has prepared design modifications and associated documentation for this transition.

Section 03.01 of the Temporary Instruction required the determination of whether the licensee appropriately implemented the NEI VII, dated March 16, 2015 (ADAMS Accession No. ML15075A454), by verifying the following:

a. Detection, Alarms and General Criteria

   1. Either open phase conditions are detected and alarmed in the control room, or

      (a) The licensee has demonstrated that open phase conditions do not prevent the functioning of important-to-safety systems, structures, and components,

      (b) Open phase condition detection will occur within a reasonably short period of time (e.g., 24 hours), and

      (c) The licensee has established appropriate documentation regarding open phase condition detection and correction.

   2. Either detection circuits are sensitive enough to identify an open phase condition for credited loading conditions (i.e., high and low loading), or if automatic detection may not be possible in very low or no loading conditions when offsite power transformers are in standby mode, automatic detection must happen as soon as loads are transferred to this standby source. Additionally, the licensee has established appropriate routine shift surveillance requirements to look for evidence of open phase conditions.

   3. Open phase condition design/protective schemes minimize misoperation or spurious action in the range of voltage unbalance normally expected in the transmission system that could cause separation from an operable offsite power source.

Licensees have demonstrated that the actuation circuit design does not result in lower overall plant operation reliability.

4. New non-Class-1E circuits are not used to replace existing Class-1E circuits.

5. The Updated Final Safety Analysis Report (UFSAR) has been updated to discuss the design features and analyses related to the effects of, and protection for, any open phase condition design vulnerability.

b. Protective Actions

1. With open phase condition occurrence and no accident condition signal present, either an open phase condition does not adversely affect the function of important-to safety system, structures, and components, or,

   (a) Technical Specification Limiting Condition of Operations (LCOs) are maintained or the technical specification actions are met without entry into Technical Specification Limiting Condition of Operation 3.0.3 (or equivalent), and

   (b) Important-to-safety equipment is not damaged by the open phase condition, and

   (c) Shutdown safety is not compromised.

2. With open phase condition occurrence and an accident condition signal present, automatic detection and actuation will transfer loads required to mitigate postulated accidents to an alternate source and ensure that safety functions are preserved, as required by the current licensing bases, or the licensee has shown that all design basis accident acceptance criteria are met with the open phase condition, given other plant design features. Accident assumptions must include licensing provisions associated with single failures. Typically, licensing bases will not permit consideration of the open phase condition as the single failure since this failure is in a non-safety system.

3. Periodic tests, calibrations, setpoint verifications, or inspections (as applicable) have been established for any new protective features.

Temporary Instruction 2515/194-03.02 - Information Gathering for Voluntary Industry Initiative Assessment (Part 2)

Section 03.02 of the Temporary Instruction required information gathering as part of the initial inspections to enable the Nuclear Reactor Regulation staff to determine whether the modifications implemented by the licensee of each unique open phase condition system design for the voluntary industry initiative adequately address potential open phase conditions. The information gathered for this section is tabulated in, "Table 1 – Information Gathered for TI 2515/194," of this report.

INSPECTION RESULTS

Based on interviews and discussions with the licensee and the vendor, review of available design, testing, grid data trending results documentation, and walkdowns of installed equipment, the team had reasonable assurance the licensee appropriately implemented, with noted exceptions discussed below, the voluntary industry initiative.

Temporary Instruction TI 2515/194-03.01 - Voluntary Industry Initiative (Part 1)

a. Detection, Alarms and General Criteria

(1) The team determined by walkdowns and observation that open phase conditions will be detected and alarmed at the local OPDP panels. The licensee was in process of integrating the alarm function into the control room for each startup transformer in the plant.

(2) The team determined that detection circuits were sensitive enough to identify an open phase condition for all credited loading conditions.

(3) No Class-1E circuits were replaced with non-Class 1E circuits in the design.

No findings were identified.

b. Protective Actions Criteria

(1) The team determined that the licensee identified they were susceptible to an open phase condition and were implementing design changes to mitigate the effects.

(2) The team determined that with an open phase condition present and no accident condition signal, the GE-ALSTOM OPDP system would not adversely affect the function of important-to-safety systems, structures, and components. The licensee's open phase condition design solution added a set of additional tripping inputs in parallel to the existing transformer isolation controls. This addition added a new tripping condition (open phase) to the electrical faults which result in loss of one preferred source of power to one train of ESF loads. The credited plant response would be the same regardless of the conditions that generated the isolation of the transformer.

No findings were identified.

c. Detection, Alarms and General Criteria Exceptions

(1) The licensee's OPDP system was operating in the monitoring mode, with third party vendor (MPR) recommendation of tighter setpoints enabled, to gather data to ensure the open phase condition design and transmission system disturbances would be accurately recorded for establishing existing range of voltage unbalance normally expected in the transmission system. Because actual demonstration of this criterion required the system to be in operation with final trip setpoints established, the team was not able to fully verify this criterion. After discussions with licensee and vendor staff, design document and test results reviews, and

historical monitoring data reviews, the team had reasonable assurance that the actuation circuit design would not result in lower overall plant operation reliability.

The team did not identify any issues of concern.

(2) The Updated Final Safety Analysis Report was currently in the draft format and therefore had not yet been updated to include information related to open phase conditions at the conclusion of the onsite inspection. However, the team reviewed two activity request AR02161401 and AR02161383 (for Units 1 and 2 respectively) developed by the licensee along with the draft write-ups which added a New UFSAR Section 8.3.1.1.4.2 for Unit 1, which described the function of the Open Phase Detection and Protection system and was captured under EC-285637 and a New UFSAR Section 8.3.1.1.2q for Unit 2 which also described the function of the Open Phase Detection and Protection system which was captured under EC-285638. The team noted during this inspection that Engineering Procurement Specification SPEC-E-086, Rev. 1, for the OPDP system changed the classification from Non-Nuclear Safety (NNS) to Quality Related which was at variance with the draft FSAR sections 8.3.1.1.4.2 and 8.3.1.1.2q which stated "The OPDP system is non-safety related." The licensee issued AR 02268419 "Update draft FSAR markup for safety class…change request stated that the open phase system is classified as non-safety…change system from Non-Safety Related to Quality Related."

The team did not identify any issues of concern.

d. Protective Actions Criteria Exceptions

(1) The licensee's open phase condition design solution used the existing isolation and power scheme for safety-related accident loads; only a new tripping condition (open phase) had been added to the electrical faults which result in loss of one preferred source of power to one train of ESF loads. A loss of voltage, including a loss of voltage caused by isolation of the preferred source due to an open phase condition, on the affected ESF bus results in the affected train loading being automatically transferred to the onsite emergency power source, if available (single failure), or manually to a different SUT. While no changes to this configuration were planned due to the inclusion of the OPDP system, actual demonstration of this criterion requires the system to be in full operation.

Through review of available design documents and discussions with plant engineering and vendor staff, the team had reasonable assurance that with an open phase condition present and an accident condition signal, the GE-ALSTOM OPDP system automatic detection and actuation would isolate the affected SUT. Due to the configuration of the St. Lucie Plant's electrical distribution system, a loss of a SUT would only affect one train of equipment, and loads required to mitigate postulated accidents would be available on the non-affected train ensuring that safety functions were preserved as required by the current licensing bases.

The team did not identify any issues of concern.

(2) The licensee had not finalized documentation for periodic tests, calibrations, setpoint verifications, or inspection procedures for open phase condition-related components at the time of this inspection. The team interviewed the licensee and vendor staff along with performing a review of the open phase condition design documents such as vendor guidance which included periodic tests, setpoint verification, equipment maintenance and inspections to gather reasonable assurance from the licensee that these details would be integrated into their plant procedures as required by their Quality Assurance Topical Report, procedures and processes.

The licensee issued the following new Action Requests (ARs) and Procedure Change Request (PCR) as a direct result of this Open Phase Condition inspection and were described as follows: AR2268313, “SPEC-E-086 section 3.3.1: Modify TS requirements for operability;” AR2259267, “Development of Maintenance procedure test procedure for OPDP system;” AR2268223, “O-NOP-99-02 – Watch station General Inspection Guidelines;” AR2268417, “Revise ECS 285637 & 285638 for MPR CALC GE Docs upload, Hold points;” AR2268308, “EC285637: Eval of min loading STPT with extended time delay” and PCR2268223, “update O-NOP-99.02 Watch station Inspection Guidelines.”

The team did not identify any issues of concern.

Table 1 – Information Gathered for TI 2515/194

A	<u>OPC Detection and Alarm Scheme</u>		Describe Observations/Comments
1	Are all credited offsite power sources specified in UFSAR Chapters 8.1, 8.2, and 8.3 and plant TSs considered in the design of OPC detection and protection schemes?	☒ Yes ☐ No	According to St. Lucie Plant (St. Lucie or PSL) UFSAR Section 8.2, three 230 KV transmission lines provide power to two units via four startup transformers (SUTs). Section 8.2.1.2 of Unit 1 UFSAR, Rev. 28 states that “A six bay 230 kV (nominal) switchyard provides switching capability for main generator output, each of the two startup transformers and the four outgoing transmission lines. The switchyard also provides switching capability for the main generator output of Unit 2 and two additional startup transformers.” Subsection 8.2.2.2.d(5) of Unit 1 UFSAR, Rev 28 states that “Physical independence of power for the startup transformers is achieved by separating their switchyard 230 KV connections in two different bays. Each bay consists of separate circuit breakers and associated equipment to connect the startup transformers with the two main 230 KV busses. Two spatially separated over-head lines are used to supply power to the startup transformers (one line for startup transformers 1A and 2A in the Unit 1 transformer yard, and one line for startup transformers 1B and 2B in the Unit 2 transformer yard).” Section 8.3.1.1.1 of Unit 1 UFSAR, Rev. 28 states that “The normal source of auxiliary ac power for plant start-up or shutdown is from the incoming off-site transmission lines through the plant switchyard and start-up transformers. The start-up transformers step down the 230 KV incoming line voltage to 6.9 KV and 4.16 KV for auxiliary system use. During normal plant operation, ac power is provided from the main generator through the unit auxiliary transformers. The unit auxiliary transformers step down the main generator output voltage from 22 KV to 6.9 KV and 4.16 KV.” The St. Lucie Open Phase Detection Protection (OPDP) system considers all credited offsite power sources.
2	Are OPC detection scheme(s) installed to monitor the qualified offsite	☒ Yes ☐ No	The St. Lucie OPDP system was installed to monitor the qualified offsite power paths to the Engineered

	power paths to the ESF buses during all modes of operation?		Safety Features (ESF) buses during all modes of operation. The General Electric (GE) fiber optic current transformer (FOCT) solutions that were installed at St. Lucie are capable of monitoring open phase conditions (OPCs) on the transmission line from the switchyard down to the SUTs for all modes of operation (such as standby mode, lightly loaded or fully loaded conditions). According to the licensee, extensive engineering analysis and testing have confirmed the range of capabilities of the FOCT solution in detecting OPCs for single and double open phase including ground conditions from no-load (with SUTs on stand-by) to full load (Mode 1) conditions. Open phase detection system logic is developed to respond to OPC under unloaded (alarm only), very lightly loaded, and noload condition (with SUT downstream breakers opened). There is a brief deadband between tripping and alarm-only settings when transiting between noload to light-load. This enables the scheme to ride through transient condition when unloaded such that spurious actuation is avoided. In addition, the difference in light load and the unloaded condition is very small and analyses is ongoing to establish that this deadband is acceptable given the relatively low current threshold for light-load condition.
3	a. What is the scope of OPCs considered by the licensee?		a. The GE FOCT solution is capable of detecting OPCs anywhere on the main transmission line between the 230kV switchyard and the SUTs for all modes of operations. The FOCT solution capability includes the detection of a single and double open phases including ground conditions. The GE FOCT is currently in the monitoring mode during which, the extracted data are being reviewed against the open phase detection logic as well as the setpoints. Any identified anomalies are also being communicated to the Vendor and the logic and setpoints are adjusted accordingly. Upon completion of the monitoring phase, the final logic and setpoints will ensure all limitations are addressed prior to the trip activation. For the SUTs light loaded condition, St. Lucie Plant has considered the delay of the trip actuation upon the OPC is detected. An evaluation is

			needed to determine the feasibility of extended time delay under this condition. It will also require revision to existing Operations procedures and associated documents to provide guidance for ensuring plant safety systems are adequately protected in events of an open phase under this condition. The evaluation is being tracked by AR 02268308.
	b. Did the licensee excluded certain OPCs (e.g., high voltage or low voltage side of power transformers), operating and loading configurations in their analyses? If so, identify the technical justifications for any exclusion.	☒ Yes ☐ No	b. Non-segregated buses are installed downstream of the SUTs all the way to the non-safety related 4.16kV and 6.9kV switchgears. The non-safety related 4.16kV switchgears feed the safety related 4.16kV switchgears which provide power to all safety related loads. Only non-safety related buses are tripped during OPCs if the SUTs are providing power to the plant equipment during the event. With the resulting loss of offsite power (LOOP) on the safety related 4.16kV buses, the plant will respond as designed and restore power to safety related loads via the Emergency Diesel Generators (EDGs). The need for an OPC monitoring system on the low voltage side of the SUTs is not warranted based on the following: • The issue is the ability to detect an OPC on the SUT high side that may potential affect the low voltage side equipment and isolate the offsite source accordingly. • Several safeguards are already in place on site to detect anomalies on the low voltage side (such as differential relays, ground fault relays, degraded voltage relays (DVRs) and loss of voltage relays (LVRs), etc.). • Maintenance of the low side power paths including switchgears, buses, protective relays, circuit breakers, and the cabling systems are performed under the periodic/preventive maintenance programs. • Various Operations and Systems Engineering walkdowns ensure that issues are identified and resolved as quickly as possible.
4	Are the detection schemes capable to identify OPCs under all operating electrical	☒ Yes ☐ No	According to the licensee, extensive engineering analysis and testing have confirmed the range of capabilities of the FOCT solution in detecting OPCs for single and double open phase including ground

	system configurations and plant loading conditions?		conditions from no-load (with SUTs on stand-by) to full load (Mode 1) conditions. The OPDP system is capable of detecting an OPC over the full range of anticipated currents on the high voltage side of the SUT. The SUTs are loaded during accident conditions, shutdown, and during Unit start-up. The SUTs are not normally loaded during Mode 1. Due to this configuration, there is minimal current passing through the SUTs during the unloaded condition. GE FOCT solution is sensitive enough to measure current down to the milliamps (mA) range during the unloaded condition. The FOCT solution also has the required range capability for the loaded condition. Furthermore, the analyses and simulations include motor loads as well as other plant loads under the various loading conditions.
5	a. If the licensee determined that OPC detection and alarm scheme was not needed, did the licensee provide adequate calculational bases or test data? b. Are all OPCs detected and alarmed in the MCR with the existing relays?	☐ Yes ☐ No ☒ N/A ☐ Yes ☒ No ☐ N/A	a. The new GE FOCT solution was designed to detect OPC and alarm in the Main Control Room (MCR) for all modes of plant operation. b. Preliminary analysis shows that a single open phase occurring on the high side of the SUT connections will go undetected especially under very lightly loaded conditions. Thus, necessitating the need for an OPDP system. The new GE FOCT solution was designed to accomplish the requirement, to detect OPC and alarm in the MCR for all modes of plant operation. Integrated testing performed on 1A and 2A SUTs during the SL1-28 refueling outage confirmed that the GE FOCT solution meets this requirement.
6	a. Are the detection and alarm circuits independent of actuation (protection) circuits? b. If the detection, alarm and actuation circuits are non-Class 1E, was there any interface with Class 1E systems?	☒ Yes ☐ No ☐ Yes ☒ No	a. The alarm and actuation circuit outputs are independent and are hard wired from different relay output terminals. b. There are no interfaces between the detection/alarm/actuation circuits and the Class 1E (safety related) systems. Under an OPC, with the SUT loaded, the non-class 1E breakers on the non-safety related 4.16kV buses are opened resulting in LOOP on the class 1E 4.16kV buses. The plant will then respond to an LOOP event as designed.

7	a. Did the manufacturer provide any information/data for the capability of installed relays to detect conditions, such as unbalanced voltage and current, negative sequence current, subharmonic current or other parameters used to detect OPC in the offsite power system?	☒ Yes ☐ No	a. The Vendor (GE) developed the OPDP system based on the commercial off the shelf Compact Sensor Intelligent (COSI) range of FOCT. GE developed the generic OPC detection logic scheme modeling Martin Plant Y-Y-Y transformer, which is similar to the St. Lucie's transformers. MPR, a Third Party Contractor, performed an independent review of the GE's OPC detection solution and subsequently modified the generic OPC detection logic scheme. MPR also reviewed various transformer winding types including Y-Y-Y (St. Lucie), Y-Δ and Δ-Y-Y (Point Beach), Y-Δ-Δ (Turkey Point), Y-Y-Y with buried Δ and Δ-Y (Duane Arnold) to develop a generic basis across the NextEra Energy fleet. To accomplish this, MPR utilized the Electro Magnetic Transient Program (known as EMTP-RV) to analyze the OPCs and the Classification and Regression Tree (CART) model to determine the impact of various parameters on the given data. Per Calculation MPR-4232, "Development of Generic Logic for GE Open Phase Detection Scheme," Rev. 3, the following parameters were used to analyze postulated OPCs: • Transformer primary and secondary side phase and line voltages, phase and line voltage angles, and corresponding sequence voltages and angles. • Transformer primary and secondary side phase currents, current angles, and corresponding sequence currents and angles. • Transformer primary and secondary side neutral currents. • Motor $I_2{}^2t$ (heat measurement corresponding to unbalance voltage) under OPCs. • Unbalance conditions which are not a result of an open phase on the primary side of the SUT including unbalance faults on the secondary side of the SUT and unbalanced offsite power voltage. For testing, per CALC-1554-0001-0001, "Martin Plant Startup Transformer Model for Open Phase

	b. What are the analyses and criteria used by the licensee to identify the		Analysis," Rev.0, dated September 16, 2015, the SUTs were tested for: • Positive sequence exciting current (positive sequence open circuit test). • Positive sequence exciting losses (positive sequence open circuit test). • Zero sequence exciting current (zero sequence open circuit test). • Zero sequence exciting losses (zero sequence open circuit test). • Positive sequence short circuit impedances (positive sequence short circuit test). • Zero sequence short circuit impedances (zero sequence short circuit test). • Winding resistances (winding resistance measurement). MPR provided generic logics and preliminary setpoint values for open phase detection. These logics and setpoints were the result of various analytical studies, field testing and RTDS [real time power system simulation tool] simulations under various OPCs for a full range of power systems' operating conditions including acceptable grid unbalance and other perturbations. These data include various combinations of phase currents (magnitude and angle) and the sequence current components obtained from the algorithms developed by the vendor for the open phase detection. Different logic paths were developed tailored towards a particular type of OPC with different parameter thresholds and time delays to ensure the system is able to ride through transients and non-open phase events. Calculations 0110-0076-CALC-001, 0110-0076- CALC-002, 0110-0076-CALC-003, and 0110-0076-CALC-004 evaluated various loading conditions in conjunction with the transmission system model for various OPC configurations. b. The OPC solution is designed to detect the various postulated OPCs (single and double open phase

	power system unbalance due to OPCs; and loading and operating configurations considered for all loading conditions which involve plant trip followed by bus transfer condition?		with and without ground). The full range of plant operating conditions (plant startup, normal power operation, and design basis accident conditions) was considered in the OPDP system design development. The OPDP system setpoints were established to provide reliable detection of postulated OPCs and adequate security to prevent inadvertent actuations due to transient events (such as motor starting or postulated faults) that do not involve OPCs. The OPDP system setpoints were established based on a combination of system modeling and simulation analysis, system commissioning data, and operating experience data captured during the monitoring period. Although not all plant evolutions such as transformer energization and in-rush transients and EDG surveillance testing are not explicitly included in the computer model and simulation analysis, these plant evolutions are being considered on the OPC system design and final system setpoints.
	c. If certain conditions cannot be detected, did the licensee document the technical basis for its acceptability?	☐ Yes ☐ No ☒ N/A	c. According to the licensee, there are no OPCs that cannot be detected with the installed system. The OPDP system can detect all types of OPC under all loading conditions (Mode 1, light load, and unloaded).
	d. Did the licensee perform functional testing to validate limitations specified by the manufacturer of the relays?	☒ Yes ☐ No	d. Functional testing including factory acceptance testing (FAT) and site acceptance testing (SAT) were performed as part of Engineering Changes (ECs) 285637 and 285638 prior to commissioning the system. The OPDP system is currently in monitoring mode during which, the extracted data are being reviewed against the OPC detection logics as well as the setpoints. Any identified anomalies are being communicated to the Vendor and Contractor for amending the OPC detection logics and setpoints accordingly. Upon completion of the monitoring phase, the final logics and setpoints should ensure all limitations are addressed prior to the activation of the system's trip function.
8	a. Do OPC detection circuit design features minimize spurious detections due to voltage perturbations observed during events which are normally	☒ Yes ☐ No	a. According to the licensee, the following design features are used in developing the OPDP system to minimize spurious detections due to voltage perturbations: • The analyses performed under MPR's St. Lucie Site Specific Open Phase Detection Calculations,

	expected in the transmission system?		(0110-0076-CALC-001, 0110-0076-CALC-002, 0110-0076- CALC-003, and 0110-0076-CALC-004), studied open phase for each SUT with different load profiles under different operating alignment including acceptable grid unbalance. The results of the studies were utilized in developing the open phase detection logics and setpoints such that this objective was met. These analyses utilized the EMTP-RV model and provided inputs for testing a relaying scheme that is able to reliably detect an OPC at the high voltage side of the SUTs being fed from offsite power circuits without false actuation due to various disturbances (e.g. transformer energization, motor starting, station faults, transmission system disturbances etc.). The EMTP-RV model was used to simulate various disturbances and observe the phase current and neutral current at the high side of the SUT. • The OPDP system includes a time-synchronized event recording provided by the satellite clock and digital fault recorder (DFR) within each OPDP cabinet. This capability allows detailed event records to be captured and reviewed. The time synchronization allows the records to be correlated with system events as needed (these systems events include on site events (via review of Operations narrative logs) and events in the switchyard and beyond (grid)). Using this equipment, St. Lucie has captured an extensive amount of data for analysis allowing refinement of the OPDP system settings. As a result, St. Lucie identified issues with the existing relay logic, these issues have now been completely resolved by the Vendor (GE). St. Lucie continues to monitor both the grid and onsite events as well as the OPDP system data to ensure all perturbations that can potentially affect the OPDP system operation are fully accounted for. • The OPDP system at St. Lucie utilizes a 2-out-of-3 logic for the protection scheme which provides defense-in-depth to prevent spurious operations. The logics are developed to respond to OPC under unloaded (alarm only) very lightly loaded, and noload condition (with SUT downstream breakers opened). There is a brief

			deadband between tripping and alarm-only settings when transiting between noload to light-load. This enables the scheme to ride through transient condition when unloaded such that spurious actuation is avoided. In addition, the difference in light load and the unloaded condition is very small and analyses is ongoing to establish that this deadband is acceptable given the relatively low current threshold for light-load condition. • The coordination between the OPDP system's trip settings and the offsite and onsite protective device settings was evaluated as part of the development of setpoint calculation (0110-0076-CALC-004). This calculation will be revised upon completion of monitoring phase and the setpoints will be finalized prior to enabling the system's trip functionality.
	b. Identify whether the licensee considered alarm/trip settings coordination with other electric power system relays including transmission system protection features setup to avoid false indications or unnecessary alarms.		b. Coordination between the OPDP system's setpoints and the existing plant protective devices (such as LVRs, DVRs, switchyard differential relays) settings and motor start time base on heating ($I_2{}^2t$) characteristics for normal grid voltage, as well as acceptable grid unbalance voltage is considered to avoid false indications or unnecessary alarms.
9	Identify how the alarm features provided in the MCR including setpoints are maintained, calibrated, and controlled.		The post-monitoring (final) alarm setpoints for the relays will be entered into new relay settings drawings (8770-A-452 series (Unit 1) and 2998-B-452 series (Unit 2)). Future changes to these settings will require a design change package (DCP) and the DCP number will be referenced in the drawings. The control of and revision to the setpoints will be controlled by the design control process per Procedure EN-AA-205-1100. Calibration is performed by injecting a known amount of current with phase angle into the FOCTs while the output of the merging units (MUs) are measured via the digital relays and the DFR, adjustments can be made to certain parameters in the MUs until the injected current is reproduced. These calibrations were performed during the FAT as well as during the

			various stages of the SAT using calibration test procedures developed by the Vendor (GE). The digital relays are calibrated via the vendor software with embedded disturbance recorder (DR), the following can be viewed via the DR and adjusted accordingly: • Compare the displayed measured values with the actual magnitudes at the terminals. • CT and voltage transformer (VT) ratios settings. • Phase displacement to confirm the inputs are correctly connected. The operations and maintenance (O&M) Manual VTM 8770-19097 provides details on how the OPDP components are to be operated and maintained. The relays and other digital components that are part of the OPDP system will be evaluated and controlled by NextEra Energy Critical Digital Asset procedures.
10	Does the OPC detection scheme consider subharmonics in the supply power or offsite power system?	☒ Yes ☐ No	The GE FOCT solution uses a combination of fiber optics technology and digital technology to filter impurities in the current being measured to ensure high accuracy of current measurement from the few mA range to Kiloamperes (kA) range. This ensures high accuracy in decision making capability regarding open phase and non-open phase conditions.
11	Are OPC detection and alarm circuit components scoped into the licensee's maintenance rule program?	☐ Yes ☐ No ☒ Other	At this time, the licensee has not determined whether or not the OPDP system will be scoped into the maintenance rule program. The determination of incorporating OPDP system into maintenance rule program will be made as part of ECs 285637 and 285638 prior to the tripping function of the system being enabled. This is being tracked by AR 2201080.
B	<u>OPC Protection scheme</u>	Yes/No	Describe Observations/Comments
1	Record location of the sensing of the protection scheme (e.g., high voltage or low voltage side of the transformer, ESF bus, etc.).		Location: High voltage (230kV) side of the SUTs
2			Classification: Safety / Non-Safety (circle one)

	a. Record the classification of the protection scheme, safety or non-safety. b. Did the licensee consider the interface requirements for non-safety with safety related circuits?	☒ Yes ☐ No	a. Non-safety b. For each Unit, the "A" train of the Plant's Auxiliary Power System is fed by the "A" train SUT while the "B" train is fed by the "B" train SUT. When the OPDP system detects an open phase on a particular train, if the SUT is loaded, the offsite power will be isolated by opening the non-safety related circuit breaker downstream of the SUT on that train. The safety related train then reacts to the LOOP per the existing design (transfers to on-site source). There is no direct interface between the new OPDP system and existing safety related systems.
3	a. Record the type of the protection scheme, digital or non-digital. b. Are cyber security requirements specified for digital detection scheme?	☒ Yes ☐ No ☐ N/A	Type: Digital / Non-Digital (circle one) a. Digital b. The cyber security evaluation was performed as part of ECs 285637 and 285638 for monitoring phase with no tie to the MCR. The components installed by this EC are considered Non-Critical Digital Assets (Non-CDAs) for the monitoring phase. Prior to go live, the EC will be revised to reclassify all OPDP system's digital assets as CDAs (except the air conditioners of the OPDP cabinets) in accordance with IM-AA-102-1002. Some of the components installed by the ECs have software equipped which were evaluated in Attachment F of the ECs and classified as Level B software.
4	Did the licensee consider any design features to prevent protective functional failures for OPC protection system?	☒ Yes ☐ No	The following design features were included in the design of the OPDP system to prevent the system's functional failures: • The OPDP system logic uses a triple redundancy scheme (2-out-of-3). A failure of any single OPDP channel does not prevent the OPDP system from performing its intended

			function. If a channel fails, the trip logic changes from 2-out-of-3 to 2-out-of-2. Thus a failure of any single component that could incapacitate a channel does not prevent the OPDP system from performing its intended function. • The 2-out-of-3 coincident logic trip circuit is wired directly to the breaker trip circuit without any auxiliary relays. Thus, the triple redundancy is not compromised. • The microprocessor relays are self-diagnosed and equipped with watchdog contacts that are activated for input data fidelity (or lack thereof). The OPDP system will send an alarm to the MCR for any of these failures and the affected relay will remove itself from the 2-out-of-3 logic. • The OPDP cabinet is provided with redundant power supplies. A loss of either power supply is alarmed in the MCR so that power to the OPDP system may be quickly restored by switching to the redundant power supply. In addition, it has been confirmed (Section 2.8.10.1 of EC 285637) that a safety signal (e.g., SIAS, CSAS, etc.) does not disconnect the power supplies to the OPDP system. • The OPDP system is provided with redundant 60 Hz references and the transition between the two reference sources is seamless. Loss of the 60 Hz reference signals will cause an alarm in the MCR. • The Cable Management Boxes (CMBs) and the OPDP cabinets utilize secure connections (e.g. terminal blocks and fiber optic patch panels). Thus a single failure (either a connection being broken, or a short circuit) is considered highly unlikely. • A comprehensive failure mode and effects analysis (FMEA) was developed for the OPDP system to identify failure modes, causes and impacts to the OPDP system functionality. A fault tree was also developed as part of the FMEA review.

			• Preventive maintenance programs will be established for periodic maintenance and calibration of the components that will help to prevent failures.
5	Identify the number of channels provided per offsite power source and if there is independence between channels and sensors.		Three (3) Channels. The OPDP system's trip circuit uses a triple redundancy scheme (2-out-of-3) coincident logic. The 2-out-of-3 coincident logic trip circuit is wired directly to the breaker trip circuit without connecting to any auxiliary relays, thus, the triple redundancy is not compromised. Each channel in the OPDP cabinet is independently connected to its own sensor, which is mounted on the high voltage side of the SUT.
6	a. What is the safety classification of power supply for the protection scheme? b. Was a loss of power to the protection scheme considered?	☒ Yes ☐ No	a. The power supply for the OPDP system's protection scheme is classified as non-safety related. b. The impacts of loss of power supply to the protection scheme have been evaluated in the FMEA as part of ECs 285637 and 285638. Each OPDP cabinet is provided with redundant power supplies. A loss of either power supply is alarmed in the MCR so that the power to the OPDP system can be quickly restored by switching to the redundant power supply. In addition, according to the licensee, it has been confirmed (Section 2.8.10.1 of EC 285637) that a safety signal (e.g., SIAS, CSAS, etc.) does not disconnect the power supplies to the OPDP system. The OPDP system is provided with redundant 60 Hz references and the transition between the two reference sources is seamless. Loss of the 60 Hz reference signals will cause an alarm in the MCR. In addition, the entire OPDP system is energized to actuate. Thus, a complete loss of power to the OPDP system will be alarmed in MCR and

			effectively remove the OPDP system out of service. Under this condition, Operations will enter into a compensatory mode (to be added to Procedures 1-AOP-53.04 (Unit 1) and 1-AOP-53.04 (Unit 2)) until the system is restored.
7	Identify if the licensee considered the consequences of a failure or malfunction of a channel.		The OPDP system installed at St. Lucie is built with 2-out-of-3 coincidence logic to provide defense-in-depth and to reduce spurious actuations. A failure of any single OPDP channel does not prevent the OPDP system from performing its intended function. If a channel fails, the trip logic changes from 2-out-of-3 to 2-out-of-2. Thus, a failure of any single component that could incapacitate a channel does not prevent the OPDP system from performing its intended function. The microprocessor relays are self-diagnosed and equipped with watchdog contacts that are activated for input data fidelity (or lack thereof). The OPDP system will send an alarm to the MCR for any of these failures and the affected relay's trip logic will change from 2-out-of-3 to 2-out-of-2. In addition, the entire OPDP system is energized to actuate. Thus, a complete loss of power to the OPDP system will effectively remove the OPDP system out of service. Under this condition, Operations will enter into a compensatory mode (to be added to Procedures 1-AOP-53.04 (Unit 1) and 1-AOP-53.04 (Unit 2)) until the system is restored.
8	Did the design consider the single failure criteria as outlined in the GDCs or the principle design criteria specified in the updated final safety analysis report?	☒ Yes ☐ No	According to the licensee, the OPDP system is a non-safety system and single failure criteria requirements does not apply. However, the implementation of the OPDP system considers this requirement in the design and implementation of the GE FOCT solution by including the design features that (a) minimize the potential of failing to detect an OPC, (b) prevent OPDP system failures from affecting the onsite power system, and (c) ensure that misoperation of the OPDP system will not affect the onsite power system. The Byron incident indicated that failure to detect an OPC could result in tripping safety related motors, which in turn could delay their restart after their loads were transferred to the EDGs. The discussion is broken down into four categories as follows:

			<u>OPDP System Separation from 1E Onsite Power</u> • All OPDP actions are on the non-safety related side of the offsite power supply. Safety related breakers (1-20209 (SUT 1A), 1-20411 (SUT 1B), 2-20209 (SUT 2A), and 2-20411 (SUT 2B)) separate the non-safety related system from the safety related circuits. • Once the safety related breakers are opened, the ensuing actions which include starting the EDGs, are unaffected. <u>OPDP System Component or Single Channel Failure</u> • A failure of any single OPDP channel does not prevent the OPDP system from performing its intended function. If a channel fails, the trip logic changes from 2-out-of-3 to 2-out-of-2. Thus, a failure of any single component that could incapacitate a channel does not prevent the OPDP system from performing its intended function. • The OPDP cabinet is provided with redundant power supplies. A loss of either power supply is alarmed in the MCR so that power to the OPDP system can be quickly restored by switching to the redundant power supply. In addition, a safety signal (e.g., SIAS, CSAS, etc.) does not disconnect the power supplies to the OPDP system. • The OPDP system is provided with redundant 60 Hz references. Loss of one or both 60 Hz reference signal causes an alarm in the MCR. • The CMB uses secure connections (e.g. terminal blocks and fiber optic patch panels). Thus, a single failure (either a connection being broken or a short circuit) is considered highly unlikely. • The OPDP cabinet also uses secure connections (e.g. terminal blocks and fiber optic patch panels). Thus, a single failure (either a connection being broken or a short circuit) is considered highly unlikely. • A break in the trip signal cable between the OPDP cabinet and the breakers could prevent the trip signal from reaching the breakers. However,

			because of the cable quality and protected route, a break is considered highly unlikely. <u>Entire OPDP System Failure</u> • All OPDP inputs and actions are on the non-safety related side of the offsite power supply. Safety-related breakers (1-20209 (SUT 1A), 1-20411 (SUT 1B), 2-20209 (SUT 2A), and 2-20411 (SUT 2B)), as applicable, separate the non-safety related system from the safety related circuits. • The only electrical connections from the OPDP system to the offsite power system is a single input to each of the SUT breakers (listed in Sections 2.3.1 of ECs 285637 & 285638). The OPDP system connections have no direct interaction with the circuits that transfer the power supply from the SUT to the onsite power system (EDGs); and therefore, a loss of the OPDP system will not preclude the onsite power system from being able to perform its intended functions. <u>OPDP System Misoperation</u> The OPDP system meets the cyber security requirements. Cyber security isolation protects (under Phase 3) the OPDP system from inputs that could redirect the system to falsely declare an OPC or to falsely ignore an OPC. Based on the above, it is determined by the licensee that while the non-safety GE FOCT solution is not required to be single-failure proof, the OPDP system is robust enough to mitigate potential single failure issues discussed in the NRC Bulletin 2012-01 and GDC-17, as documented in the Volunteered Industry Initiative for nuclear plant auxiliary power transformers, as documented in ECs 285637 and 285638.
9	a. Did the licensee identify the industry standards and criteria to verify power quality issues caused by OPCs that affect redundant ESF buses?	☐ Yes ☒ No ☐ N/A	a. There are various technical journals that discuss aspects of OPC (classified as series fault) but there were no specific industry standards at the time of development of the Fiber Optic Open Phase Technology that specifically focused on OPC. However, the following technical reports, which were being developed at about the same time the Fiber Optic Solution was being developed, were utilized as analytical aspects of the OPC detection scheme development:

	b. What industry standards were used to develop the acceptance criteria for OPC trip setpoint or analytical limit?		• Open Phase Detection For Power Transformers Using VT Triggered Optical CTS and IEC 61850-9.2LE Compliant Relays • Flexible Free Form Factor Digital Optical Current Sensor b. The OPDP system uses a combination of parameters such as phase currents (magnitude and phase angle) and a combination of current sequence components, to determine an OPC. From a combination of OPC simulations and field tests as well as FAT and SAT test reports and monitoring period data review, the final setpoints will be determined. PSL Calculation 0110-0076-CALC-004 establishes the acceptance criteria for the setpoints for the OPDP system in Section 4.0. The open phase current threshold setpoints are selected to detect the OPC as analyzed in Calculation 0110-0076-CALC-003 but does not trip on non-open phase conditions. Calculation 0110-0076-CALC-003 establishes the expected currents during the various OPCs that could occur. Therefore, the current settings are based on analysis performed by PSL. The time delay trip setpoints are established based on the following criteria: • The maximum time delay of the OPDP system should be less than the DVRs time delay to ensure that the individual motor circuits will not trip considering the motor stalling. This acceptance criteria is achieved by coordinating the open phase relays with the DVRs and motor overcurrent relays settings. • The minimum time delay of the OPDP system should be greater than the LVRs time delay setpoint. This acceptance criteria is achieved by coordinating the OPDP system with the LVRs settings. • The time delay of the OPDP system must be greater than the PSL switchyard differential protection relays. This coordination allows a fault to be isolated by the differential protection scheme prior to actuation of the OPDP system.

			• The maximum time delay must ensure that the total motor $I_2{}^2t$ measurement is maintained less than 40 pu.s (per unit seconds). This acceptance criteria is to ensure that the motor is not damaged as a result of the OPC. This is based on MPR Calculation DRN-0200-0162-001.
10	What are the analytical limits or criteria used for setpoints of the actuation/protection scheme to provide adequate protection for motors and sensitive equipment?		The acceptance criteria used for establishing setpoints for the open phase analysis to ensure protection of motors is maintaining the $I_2{}^2t$ less than 40 pu.s to ensure motor damage does not occur. The acceptance criterion is established in the setpoint calculation 0110-0076-CALC-004. This acceptance criterion within the calculation was established based on MPR Calculation DRN-0200-0162-001.
11	What are the design features provided to preclude spurious trips of the offsite power source (e.g. coincidence logic)?		According to the licensee, the following design features are provided to preclude spurious trips of the offsite power source: • A failure of any single OPDP channel does not prevent the OPDP system from performing its intended function. If a channel fails, the trip logic changes from 2-out-of-3 to 2-out-of-2. Thus, a failure of any single component that could incapacitate a channel does not prevent the OPDP system from performing its intended function. • The OPDP cabinet is provided with redundant power supplies. A loss of either power supply is alarmed in the MCR so that power to the OPDP system can be quickly restored by switching to the redundant power supply. In addition, a safety signal (e.g., SIAS, CSAS, etc.) does not disconnect the power supplies to the OPDP system. • The OPDP system is provided with redundant 60 Hz references. Loss of one or both 60 Hz reference signal causes an alarm in the MCR. • The Cable Management Box uses secure connections (e.g. terminal blocks and fiber optic patch panels). Thus, a single failure (either a connection being broken or a short circuit) is considered highly unlikely.

			• The OPDP cabinet also uses secure connections (e.g. terminal blocks and fiber optic patch panels). Thus, a single failure (either a connection being broken or a short circuit) is considered highly unlikely. • A break in the trip signal cable between the OPDP cabinet and the breakers could prevent the trip signal from reaching the breakers. However, because of the cable quality and protected route, a break is considered highly unlikely. • The relays are energized to actuate. Thus, a complete loss of functionality (due to the loss of power or any other reason) will not result in spurious trip leading to loss of offsite power.
12	a. What analyses have been performed by the licensee which demonstrates that the OPCs do not adversely affect the function(s) of important-to-safety equipment required for safe shutdown during anticipated operational occurrences, design basis events, and accidents? If an analyses was not performed, what justification was provided? b. Are bus transfer schemes and associated time delays considered?	☒ Yes ☐ No	a. According to the licensee, extensive analysis were performed in Calculations 0110-0076-CALC-001, 0110- 0076-CALC-002, 0110-0076-CALC-003, and 0110-0076-CALC-004 for the St. Lucie plant ranging from transformer modeling, plant configuration, different operating conditions several analytical studies as well as setpoint calculations with due considerations for both open phase and non-open phase conditions. Coordination between the OPDP system setpoints and existing plant protective devices (such as LVRs, DVRs, switchyard differential relays) settings and motor start time base on heating ($I_2{}^2t$) characteristics for normal grid voltage, as well as acceptable grid unbalance voltage is considered. b. Time delay schedules are provided in Table 2-1 Calculation 0110-0076-CALC-004. These time delays provide adequate margin for the OPDP system to ride through various transients including large motor starts, and other anticipated grid transients. This calculation will be revised based on the evaluation of the actual data gathered during monitoring period to ensure that assumptions and setpoints are still bounding or adjusted as necessary.

Table 1 – Information Gathered for TI 2515/194

13	Are OPC protection/actuation circuit components scoped, as appropriate, into the licensee's maintenance rule program?	☐ Yes ☐ No ☒ Other	The maintenance rule impact is currently being evaluated and tracked by AR 02172282. The result of the evaluation will be documented in the EC revisions for trip activation.
C	<u>UFSAR Updates to Reflect the Need to Protect Against OPCs:</u> Using items 1 to 6 below as examples, identify whether the licensee has updated the UFSAR (and supporting documents such as calculations of record, design change modifications, etc.) to ensure plant-specific licensing basis/requirements include discussions of the design features and analyses related to the effects of, and protection for, any open phase condition design vulnerability.	☐ Yes ☐ No ☒ Other	Describe Observations/Comments Engineering Changes 285637 & 285638 evaluated the OPDP system installation to allow for data collection and performance monitoring of the new system in accordance with Procedure EN-AA-100-10001. These ECs performed overall installation of the OPDP system as well as enabling the monitoring and alarm capabilities of the system. Review of the ECs concluded that the monitoring and alarm-only capabilities of the new OPDP system would be below the level of detail contained in the UFSAR. Therefore, according to the licensee, it wasn't necessary to revise the UFSAR to include the OPDP system's monitoring and alarm-only capabilities. Revision of these ECs for trip activation will include the evaluation of the need for the Licensing Basis Documents and UFSAR updates to be submitted under 50.71. UFSAR Updates is being tracked via ARs 02161383 (Unit 1) and 02161401 (Unit 2).
1	The plant-specific analysis and documentation that established the resolution of the OPC design vulnerability, including the failure mode analysis performed.	☒ N/A	
2	Description of OPC automatic detection scheme, including how offsite power system OPCs are detected from sensing to alarm devices (loss of one or two phases of the three phases of the offsite power circuit both with and without a high-impedance ground fault condition on the high-voltage side of all credited qualified offsite power sources under all loading and operating	☒ N/A	

	configurations; and loss of one or two phases of three phases of switchyard breakers that feed offsite power circuits to transformers without ground.		
3	Detection circuit design features to minimize spurious indications for an operable offsite power source in the range of voltage perturbations, such as switching surges, transformer inrush currents, load or generation variations, and lightning strikes, normally expected in the transmission system.	☒ N/A	
4	Alarm features provided in the MCR. Discuss the ESF bus alignment during normal plant operation and the operating procedures in place to address OPCs. If the plant auxiliaries are supplied from the main generator and the offsite power circuit to the ESF bus is configured as a standby power source, then OPCs should be alarmed in the MCR for operators to take corrective action within a reasonable time.	☒ N/A	
5	Describe the automatic protection scheme provided for OPCs including applicable industry standards used for designing the scheme. Design features to minimize spurious actuations for an operable offsite power source in the range of voltage perturbations, such as switching surges, transformer inrush currents, load or generation variations, and lightning strikes, normally expected in	☒ N/A	

	the transmission system should be described.		
6	Brief discussion of the licensee's analyses performed for accident condition concurrent OPCs which demonstrate that the actuation scheme will transfer ESF loads required to mitigate postulated accidents to an alternate source consistent with accident analyses assumptions to ensure that safety functions are preserved, as required by the licensing bases.	☒ N/A	
D	<u>TS Surveillance Requirements and LCO for Equipment Used for OPC Mitigation</u>		Describe Observations/Comments
1	a. Are TSs Surveillance Requirements and LCO for equipment used for the mitigation of OPC identified and implemented consistent with the operability requirements specified in the plant TSs? b. If the licensee determined that TSs are unaffected because OPC is being addressed by licensee-controlled programs, is the technical justification adequate?	☒ N/A ☒ Yes ☐ No	a. According to the licensee, the OPDP system is not subject to TS surveillance requirements or an LCO. b. The OPDP system is a non-safety related enhancement to the existing offsite power protection scheme. As such, the OPDP system is not subject to TS surveillance requirements or an LCO. Periodic maintenance will be performed on the OPDP system in accordance with St. Lucie periodic maintenance program. If the OPDP system is out of service, the compensatory measures will be implemented as outlined in attachments 9 & 10 (for A & B Trains respectively) of Start-up Transformer Abnormal Operating Procedure (1[2]-AOP-53.04 via PCR 2243077[2246951]) to protect 1E systems from an OPC.
E	<u>Provide a brief summary of the OPC plant modification</u>	Engineering Changes 284526 and 284527 installed the FOCTs on SUTs 1A/2A and 1B/2B respectively as Phase 1 of the Open Phase project. The installation includes installing the FOCT	

	performed under 10 CFR 50.59.	housing rings on the high voltage bushings of each transformer, installing a CMB near each SUT and routing the FOCT cables to the associated CMB located on the respective SUT. The fiber optic and copper feeder cables are routed from the FOCT modulator to the CMB. Phase 2 of the project involves the installation of the OPDP cabinets and connecting the Phase 1 equipment to the Alstom COSI units and relays. The OPDP system is currently in monitoring mode during which, the extracted data are being reviewed against the OPC detection logics as well as the setpoints. Any identified anomalies are being communicated to the Vendor and Contractor for amending the OPC detection logics and setpoints accordingly. Upon completion of the monitoring phase, the final logics and setpoints should ensure all limitations are addressed prior to the activation of the system's trip function.

DOCUMENTS REVIEWED

71111.01: Adverse Weather Protection
OP-AA-102-1002, Seasonal Readiness, revision 25
0-AOP-53.02, Low Voltage Switchyard Voltage, revision 3
0-AOP-53.03, High Voltage Switchyard Voltage, revision 1
0-AOP-53.04, Reduced Offsite Transmission Capability, revision 7
WM-AA-200, Work Management Process Overview, revision 18
ADM-16.01, PSL Switch Yard Access / Work Control, revision 14
1-AOP-24.01, RAB Flooding, revision 10
2-AOP-24.01, RAB Flooding, revision 10
Drawing 2998-G-839, Flood Control Stop Logs, revision 3
U2 Technical Specification 3/4.7.6, Flood Protection, Amendment No. 82
U1 UFSAR Section 2.4.3, Hydrology, Amendment 28
U2 UFSAR Section 2.4.3, Hydrology, Amendment 24
U1 UFSAR Section 3.4, Water Level (Flood) Design, Amendment 28
U2 UFSAR Section 3.4, Water Level (Flood) Design, Amendment 24

71111.04: Equipment Alignment
1-NOP-03.11, LPSI System Initial Alignment, revision 4
1-NOP-09.11, Auxiliary Feedwater System Initial Alignment, revision 10
1-NOP-14.01, Component Cooling Water System Initial Alignment, revision 28
1-NOP-59.01B, 1B Emergency Diesel Generator Standby Alignment, revision 11

71111.05: Fire Protection
ADM-0005729, Fire Protection Training, Qualification and Requalification, revision 26
ADM-19.02, Pre-Fire Plan Standard Operating Procedure, revision 3

71111.11: Licensed Operator Requalification Program and Licensed Operator Performance
2-AOP-99.01, Loss of Tech Spec instrumentation, revision 10
2-EOP-01, Standard Post Trip Actions, revision 38
2-EOP-10, Station Blackout, revision 26
2-EOP-99, Appendix V, Receiving AC Power from Unit 1 using SBO Crosstie, revision 60
EPIP-01, Classification of Emergencies, revision 26
EPIP-02, Duties and Responsibilities of the Emergency Coordinator, revision 44
EPIP-08, Offsite Notifications and Protective Action Recommendations, revision 44
2-GOP-123, Turbine Shutdown – Full Load To Zero Load, revision 63
1-GOP-201, Reactor Plant Startup – Mode 2 to Mode 1, revision 135

71111.12: Maintenance Effectiveness
ER-AA-100-2002, Maintenance Rule Program Administration, revision 6
SCEG-004, Guideline for Maintenance Rule Scoping, Risk Significant Determination, and Expert Panel Activities, revision 3
AR 2253840, MV-21-3 did not fully close during testing, dated April 11, 2018

71111.13: Maintenance Risk Assessments and Emergent Work Control
OP-AA-104-1007, Online Aggregate Risk, revision 4
WCG-016, Online Work Management, revision 34

71111.18: Plant Modifications
EN-AA-205-1100, Design Change Packages, revision 23

71111.20: Refueling and Other Outage Activities
ADM-09.23, Outage Risk Assessment and Control, revision 20
1-GMM-68.02, Emergency Closure of Containment Penetrations, Personnel Hatch, and Equipment Hatches, revision 18
1-NOP-03.05, Shutdown Cooling, revision 62
1-NOP-01.05, Filling and Venting RCS, revision 48
1-NOP-02.02, Charging and Letdown, revision 64
ADM-09.26, Shutdown Cooling Controls, revision 1
1-GOP-302, Reactor Plant Startup – Mode 3 to Mode 2, revision 53
1-GOP-303, Reactor Plant Heatup – Mode 3 < 1750 to Mode 3 > 1750, revision 43
1-GOP-365, Refueling Sequence Guidelines, revision 63
1-GOP-403, Reactor Plant Heatup – Mode 4 to Mode 3, revision 49
1-GOP-504, Reactor Plant Startup – Mode 5 to Mode 4, revision 70

71111.22: Surveillance Testing
ADM-29.02, ASME Code Testing of Pumps and Valves, revision 17

71151: PI Verification Inspection
Procedures, Guidance Documents and Manuals
LI-AA-100-10003, NRC Performance Indicator, revision 1

OTHER ACTIVITIES
TEMPORARY INSTRUCTION 2515/194:

Procedures:
1-ARP-01-A00, Annunciator Response Procedure, Control Rm. Panel A RTGB-101, Rev. 24
1-AOP-53.04, Abnormal Operating Procedure, Start Up Transformer, Rev. 7
1-AOP-50.05, Abnormal Operating Procedure, 125V DC Bus 1C Ground Isolation, Rev. 3
1-AOP-50.06, Abnormal Operating Procedure, 125V DC Bus 1D Ground Isolation, Rev. 2
1-AOP-50.05, PCR 2251374, 125V DC Bus 1C Ground Isolation, Rev. 3
1-AOP-50.06, PCR 2251374, 125V DC Bus 1D Ground Isolation, Rev. 2
1-AOP-53.04, PCR 2243077, Start-Up Transformer, Rev. 8
1-ARP-01-A00, PCR 2243077, Control Room Panel A RTGB-101, Rev. 26
1-ARP-01-B00, PCR 2243077, Control Room Panel A RTGB-101, Rev. 33
1-NOP-53.11_001_2 r1 “Main Transformer Backfeed” dated: 9/29/16
2-AOP-50.05, PCR 2251374, 125V DC Bus 2C Ground Isolation”, Rev. 3
2-AOP-50.06, PCR 2251374, 125V DC Bus 2D Ground Isolation”, Rev. 2
2-AOP-53.04, PCR 2246951, Start-Up Transformer, Rev. 6
2-ARP-01-A00 PCR 2246951, Control Room Panel A RTGB-201, Rev. 26
2-ARP-01-B00 PCR 2246951 “Control Room Panel B RTGB-201”, Rev. 29
2-NOP-53.11_001, Main Transformer Backfeed, Rev. 1
EN-AA-100-1003, NEXTERA Energy, Control of Design Interfaces, Rev. 2
EN-AA-100-1004, NEXTERA Energy, Calculations, Rev. 7
EN-AA-203-1102, NEXTERA Energy, Safety Classification Determination, Rev. 6
MPR-4232, Development of Generic Logic for GE Open Phase Detection Scheme, Rev. 3

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8770-B-327-SH903-EC285637, “Control Wiring Diagram – Start-up Standby Transformer 1B Lockout Relay”, Rev. 1
8770-B-327, SHT 901-EC285637, Hutchinson Island Plant-Unit No. 1, Control Wiring Diagram, Start Up Transformer 1A Lockout Relay, Rev. 0
8770-18740, Startup Transformer 1A, Wiring Diagram, Cable Manager Box CMB-1A, Rev. 1
8770-B-327, SHT 904-EC285637, Control Wiring Diagram, Startup Trans 1A-1 BKR, Rev. 0
8770-B-327, SHT 905-EC285637, Control Wiring Diagram, Startup Trans 1B-1 BKR, Rev. 0
8770-B-327, SHT 905-EC285637, Control Wiring Diagram, Startup Standby Transformer 1B, Lockout Relay, Rev. 0
8770-B-327, SHT 906-EC285637, Control Wiring Diagram, Startup Trans 1A-2 BKR, Rev. 1
8770-B-327, SHT 907-EC285637, Control Wiring Diagram, Startup Trans 1B-2 BKR, Rev. 0
8770-B-327, SHT 1022-EC285637, Station Auxiliary B, Annunciator-B SH 1, RTGB-101, Rev. 0
8770-B-327, SHT 1022-EC285637, Station Auxiliary B, Annunciator-B SH 1, RTGB-101, Rev. 17
8770-B-327, sheet 1971-EC285637, Control Wiring Diagram, Open Phase Detection, Start Up Transformer 1A FOCT, Rev. 0
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8770-B-327, sheet 1978-EC285637, Control Wiring Diagram, OPDP Cabinet 1A, Rev. 2
8770-B-327, sheet 1979-EC285637, Control Wiring Diagram, OPDP Cabinet 1B, Rev. 2
8770-B-327, SHT 1020-EC285637, Hutchinson Island Plant – Unit No. 1, Control Wiring Diagram, Station Auxiliary A, Annunciator-B SH 1, RTGB-101, Rev. 0
2998-B-327, sheet 2011-EC285638, Control Wiring Diagram, OPDP Cabinet 2A, Rev. 0
2998-B-327, sheet 2012-EC285638, Control Wiring Diagram, OPDP Cabinet 2B, Rev. 0
8770-G-340-EC285637, Turbine Building Ground Floor Conduits, Trays and Ground – Sh.2, Rev. 2
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8770-G-409, Sh.2-EC285637, Transformer Yard Plan Transformer Fire Protection and 5KV & 6.9KV Non-SEG Bus Duct, Rev. 0
EC285637-E-001, Turbine Building Ground Floor Conduit Layout, Rev. 1
EC285637-E-002, Transformer Yard Conduit Layout Rev. 0
EC285637-E-003, Transformer Yard Conduit Layout, Rev. 1

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0110-0076-CALC-001, Startup Transformer Models for St. Lucie Units 1 and 2, Rev. 0
0110-0076-CALC-002, PSL EMPT-RV Plant Model Calculation, Rev. A
0110-0076-CALC-003, PSL EMPT-RV Results, Calculation, Rev. B
0110-0076-CALC-004, PSL GE OPC System Setpoint Calculation, Rev. A
CALC-1554-0001-0001, “Martin Plant Startup Transformer Model for Open Phase Analysis,” Rev.0
EDQ199920020071, 480VAC Motor Control Centers, Cable and Bus Protection / Breaker Coordination, Rev. 28

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EC-285638, Open Phase and Detection, Rev. 3,

EC 284526, 10CFR Applicability Determination Form “EC284526 – Open Phase - FOCT Installation – Startup Transformers 1A & 2A, Rev. 0

Miscellaneous Documents:

OPD-EMC-001, Rev. 0 “EMC Compliance for Open Phase Detection Protection Cabinet”, dated: 11/10/2017

200777 JR108251.OD-03 “Digital Instrument Transformers GE Energy Connections - Validation of GE OPD System: Inducing Low Power Faults on Unloaded Delta & Wye High-side Transformers” dated: 4/14/2016

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FPL-1, NEXTERA Energy, Florida, Power and Light Company, NexEra Energy Seabrook, LLC, Quality Assurance Topical Report, Rev. 21

FPL Martin Plant 238 kV Transformer Open-phase Detection Testing Wye High Side. by Digital Instrument Transformer Group, 8/12/14

SPEC-E-086, Engineering Procurement Specification for Open Phase Detection and Protection (OPDP) System for NextEra Energy (NEE Nuclear Fleet), Rev. 5

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ABB, FPL TSO, Alstom GE Acceptance of FOCT Mounting – Letter from Juan Santana ABB International Segment Manager reply to Tony Z. Song at Sargent Lundy, 11/2/15

NEXTERA Energy INC, Fleet Open Phase Project, ENERCON, Independent Third Party Review (ITPR) of MPR Calculation for St. Lucie, 1A/2A and 1B/2B Startup Transformers: 0110-0076-CALC-001R0, 0110-0076-CALC-002RA, 0110-0076-CALC-003RB

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CSA/IEC 60044-8/IEEE C57.13-1993, Routine Test Results, NXCT Current Sensor System, Chassis S/N NXCT-1206, 4/14/16

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AR-02161401 EC285638 UFSAR Change Request
AR-02161383 EC285637 UFSAR Change Request

Corrective Action Program (CAP) Documents, Generated:

PCR2268223 update O-NOP-99.02 Watch station Inspection Guidelines
AR 02268308 Evaluation of Min. Loading STPT with extended time delay
AR 02259267 Development of Maintenance test procedures for OPDP System
AR 02268313 SPEC-E-086 section 3.3.1, Modify TS requirement for operability
AR 02268417 Revise ECS 285637 & 285638 for MPR CALC GE Docs upload
AR 02268419 ECS 285637 285638: Update draft FSAR markup for safety classification,
open phase system classified as non-safety, however, open phase system has been classified as Quality related