91

FPUC's Response to OPC's Fourth Set of Interrogatories Nos. 21-46

Interrogatory No. 21

INTERROGATORIES

21. Please refer to the SPP, on pages 4 and 5, FPUC states that there "may be some costs associated with these programs already included in the base rates approved for the Company," and please identify which programs.

Response:

a) Distribution Pole Inspections and Replacements

b) Transmission System Inspection and Hardening

c) Transmission & Distribution Vegetation Management

Respondent: Mark Cutshaw

Interrogatory No. 22 (a)

22. Please refer to the SPP on page 6, FPUC discusses "the importance of identifying potential pitfalls early, and the validation of initial assumptions," and respond to the following"

a. For each of the ten programs, identify each pitfall discussed for the program.

Response:

1) Overhead Feeder Hardening

Things such as the availability of material, resource constraints, costs, customer interface, contractor interface/coordination, planned outage requirements, and timing were discussed.

2) Overhead Lateral Hardening

Same as 1.

3) Overhead Lateral Undergrounding

Same as 1.

4) Distribution Pole Inspections & Replacements

N/A - This is an existing program, but discussion held on need to reduce the pole replacement backlog.

5) Transmission & Substation Resiliency

The ability to get the equipment necessary to construct the project and get all the necessary agreements in place to ensure this functions as proposed.

6) Transmission System Inspections & Hardening

N/A - This is an existing program, but discussion held on need to accelerate the elimination of 69kV Wood Poles on the system.

Interrogatory No. 22(a), cont.

7) Transmission & Distribution Vegetation Management

N/A - This is an existing program with only trim cycle adjustments.

8) Future Transmission & Distribution Enhancements

The system requirements necessary to implement such enhancements such as load capacity and circuit connectivity were discussed. This required additional research and planning that may have placed unnecessary burden on FPUC resources while they focused on ensuring the successful implementation of other aspects of the plan and on customers who would have been impacted by multiple SPP Programs at once.

Respondent: Mark Cutshaw

Interrogatory No. 22(b)

b. For each pitfall above, discuss the mitigation plan to reduce or eliminate the pitfall.

Response:

1) Overhead Feeder Hardening

2022 was selected to be a design only year with construction not scheduled to commence until 2023. Additionally, one of the shorter feeders amongst the risk ranked list was selected for 2022 and investments in the program were methodologically increased over the first three years of the plan.

2) Overhead Lateral Hardening

Same as 1.

3) Overhead Lateral Undergrounding

Same as 1.

4) Distribution Pole Inspections & Replacements

Additional funding was allocated to years 2023-2027 of the plan to accelerate the backlog reduction.

5) Transmission & Substation Resiliency

Agreements will be discussed during 2022 to ensure the future ability to access additional generation capabilities for Amelia Island.

6) Transmission System Inspections & Hardening

Additional funding was allocated to years 2027-2031 of the plan to accelerate the wood pole elimination and postpone rate impacts until after the Transmission & Substation Resiliency program.

Interrogatory No. 22(b)

7) Transmission & Distribution Vegetation Management

Additional funding was allocated to accommodate the proposed trim cycle.

8) Future Transmission & Distribution Enhancements

Program was deferred until 2025

Respondent: Mark Cutshaw

Interrogatory No. 22(c)

c. Discuss each of the assumptions used in developing the programs.

Response: Please reference the previously provided "FPUC Model & Targets" worksheet from OPC's POD's 1-2, specifically the tab labeled "10YrPlan"

Respondent: Mark Cutshaw

Interrogatory No. 22(d)

d. For each assumption, discuss how that assumption was validated.

Response: Some assumptions, cost per mile as an example, cannot be validated until projects are completed. As price of materials and labor fluctuate, cost assumptions will never be fully validated but rather adjusted as needed. Other assumptions such as the percentage of line miles associated with worst performing single phase laterals were validated for year 1 projects as part of the target selection process. The adjusted number was then utilized in projecting the full program costs noted on the plan.

Respondent: Mark Cutshaw

Interrogatory No. 23(a)

23. Please see page 13 of the SPP, Overhead Feeder Hardening, and answer the following:

a. Describe the methods used to prioritize the hardening of feeders.

Response: FPUC implemented a systematic method of addressing and maintaining ongoing compliance with the requirements of the Rule. The Plan is grounded on a strategy that prioritizes feeders by leveraging the Risk Resiliency Model, focuses on feeders with the highest risk score, hardens the entire feeder backbone, hardens all multi-phase overhead laterals, and strategically undergrounds the worst performing single phase laterals.

As part of this process, FPUC:

- Collected data on the FPUC system and feeders.
- Risk ranked the feeders in a Risk Resiliency Model.
- Adjusted the deployment timing of the highest risk ranked feeders within the initial ten-year window based on several factors (e.g., potential DOT work, intent to start small in early years of the plan, finalizing remaining coastline exposure on section of a feeder, etc.).
- Calculated projected cost for identified projects based on cost estimates for programs of similar scope and known targeted units (mileage). In the cases for which specific mileage was not known, reasonable assumptions were drawn which were then updated as data was validated.
- Divided project deployment into multiple phases to minimize the impact to customer rates within a calendar year and to achieve the desired investment ramp-up strategy noted on the Plan.

Respondent: Mark Cutshaw

Interrogatory No. 23(b)

b. Include any weighting factor for each criterion contained in the SPP (pages 21 to 23).

Response: As noted in Section 2 of FPUC's SPP Proposal, FPUC leveraged the assistance of Pike Engineering and their proprietary Resiliency Risk Model to evaluate the FPUC distribution system and develop a prioritized list of investment projects. The Resiliency Risk Model leverages an algorithm that assesses a balanced approach between Probability, Response, and Impact. Because of the requirement in the Rule to focus on identifying investments that would "strengthen electric infrastructure" and thus "reduce outage times and restoration costs" associated with extreme weather events, the algorithm was biased towards the Impact category.

Respondent: Mark Cutshaw

Interrogatory No. 23(c)

c. Provide a prioritized list of feeders to be hardened in the next 3 years.

Response: Please reference the previously provided "FPUC Model & Targets" worksheet from OPC's POD's 1-2, specifically the tab labeled "10YrPlan"

Respondent: Mark Cutshaw

d. Provide the societal impact for each analyzed scenario for the feeders to be hardened in the next 3 years.

Response: Data made available to FPUC as part of the output from the Resiliency Risk Model is the overall Resiliency Risk Score by feeder and not subsets based on each of the three focus categories.

Respondent: Mark Cutshaw

Interrogatory No. 23(e)

e. Do any of the feeders analyzed have societal cost savings greater than the proposed hardening costs? If so, provide such data.

Response: FPUC did not calculate societal cost savings for the analyzed feeders.

Respondent: Mark Cutshaw

Interrogatory No. 23(f)

f. Provide a cost benefit analysis for Distribution Feeder Hardening.

Response: Please reference Section 3 of FPUC's SPP detailing the costs and benefits of the Overhead Feeder Hardening Program.

Respondent: Mark Cutshaw

Interrogatory No. 23(g)

g. For each of the 29 feeders, provide the number of customers served.

Response: Please reference the previously provided "FPUC Model & Targets" worksheet from OPC's POD's 1-2, specifically the tab labeled "FeederData".

Respondent: Mark Cutshaw

Interrogatory No. 23(h)

h. The average cost for Feeder hardening in Table 2 is $395,274 per mile. Compare this cost to the cost per mile in Table 12 which is only $40,214 per mile. Please explain the difference in the cost per mile and the impact on the cost benefit of feeder hardening.

Response: Table 2 details the projected full project costs for Overhead Feeder Hardening jobs (engineering and construction). Table 12 details the 2022 costs associated with this Program. As noted on the plan, there are no planned construction activities in 2022 (only engineering), thus table 12 is reflective of projected engineering costs for the noted projects within the Overhead Feeder Hardening Program.

Respondent: Mark Cutshaw

24. Please see page 13 of the SPP, Overhead Lateral Hardening, and respond to the following:

a. Describe the methods used to prioritize the hardening of laterals.

Response: FPUC implemented a systematic method of addressing and maintaining ongoing compliance with the requirements of the Rule. The Plan is grounded on a strategy that prioritizes feeders by leveraging the Risk Resiliency Model, focuses on feeders with the highest risk score, hardens the entire feeder backbone, hardens all multi-phase overhead laterals, and strategically undergrounds the worst performing single phase laterals.

As part of this process, FPUC:

- Collected data on the FPUC system and feeders.
- Risk ranked the feeders in a Risk Resiliency Model.
- Adjusted the deployment timing of the highest risk ranked feeders within the initial ten-year window based on several factors (e.g., potential DOT work, intent to start small in early years of the plan, finalizing remaining coastline exposure on section of a feeder, etc.).
- Calculated projected cost for identified projects based on cost estimates for programs of similar scope and known targeted units (mileage). In the cases for which specific mileage was not known, reasonable assumptions were drawn which were then updated as data was validated.
- Divided project deployment into multiple phases to minimize the impact to customer

rates within a calendar year and to achieve the desired investment ramp-up strategy noted

on the Plan.

- Allocated costs within the 10-year period by aligning the Engineering and Construction of feeders and laterals of the same feeder within same calendar years to ensure resource efficiencies.
- Identified specific laterals to be hardened in the first year of the plan by establishing statistical thresholds and validating outage information against GIS data to group downstream fuses together.

Respondent: Mark Cutshaw

Interrogatory No. 24(b)

b. Provide a prioritized list of laterals to be hardened in the next 3 years.

Response: Please reference the previously provided "FPUC Model & Targets" worksheet from OPC's POD's 1-2, specifically the tab labeled "Targets" containing the prioritized list of laterals for 2022 and 2023. The 2024 targets will be design only targets located on other feeders as noted on the tab labeled "10YrPlan" within the same worksheet. The prioritization of those 2024 design only laterals has not been performed.

Respondent: Mark Cutshaw

c. Provide the societal impact for each analyzed scenario for the laterals to be hardened in the next 3 years.

Response: Data made available to FPUC as part of the output from the Resiliency Risk Model is the overall Resiliency Risk Score by feeder and at the feeder level. Individual laterals were not analyzed through the model and were prioritized within the feeder as noted on 24(a) above.

Respondent: Mark Cutshaw

Interrogatory No. 24(d)

d. Do any of the laterals analyzed have societal costs savings greater than the proposed hardening costs? If so, provide such data.

Response: FPUC did not calculate societal cost savings for the analyzed laterals.

Respondent: Mark Cutshaw

Interrogatory No. 24(e)

e. For each of the laterals to be hardened in the next 3 years provide the number of customers served by the lateral.

Response: Please reference Section 6.2 of FPUC's SPP detailing the number of customers served by the laterals identified in year 1 of the plan. The number of customers for laterals flagged for hardening in years 2 and 3 of the plan is not readily available.

Respondent: Mark Cutshaw

Interrogatory No. 24(f)

f. Provide a cost benefit analysis for lateral hardening.

Response: Please reference Section 3.2 of FPUC's SPP detailing the costs and benefits of the Overhead Lateral Hardening Program.

Respondent: Mark Cutshaw

Interrogatory No. 24(g)

g. Describe the "specialized software" used to ensure adherence to NESC Standards.

Response: PowerLine Technology's PoleForeman and SagLine software assist engineers in assuring adherence to NESC clearance and loading standards while DSTAR's SEDS software assists with secondary loading and design.

Respondent: Mark Cutshaw

Interrogatory No. 24(h)

h. Does this "specialized software" ensure adherence to all NESC Standard or some subset of the standards?

Response: No. The NESC covers a broad range of topics from generation facilities, overhead construction, underground construction, work rules, and others. PoleForeman and SagLine software focuses on overhead construction; specifically loading and clearances as they relate to the NESC requirements. As with most software systems, it is the responsibility of the Engineer to input the correct and appropriate data within the software tool in order to yield the correct and expected results of the analysis.

Respondent: Mark Cutshaw

Interrogatory No. 24(i)

i. Provide the conductor size and type used for materials that," better withstand damage from airborne debris" (page 27).

Response: Conductor of smaller diameter and made of copper (e.g., #6 cu) have proven to be problematic during extreme weather events, both in their ability to withstand damage from airborne debris such as tree limbs and do not benefit from automatic sleeves that facilitate the restoration process. Intent is to upgrade these smaller conductors, as needed, along the targeted lateral sections to #1/0 Al (AAAC).

Respondent: Mark Cutshaw

Interrogatory No. 24(j)

j. The cost per mile for overhead feeder lateral hardening for 2022, 2023 and 2024 is $689,655 per mile (see Table 3, page 27). Justify why hardening a lateral with small conductor sizes and an average cost of $395,274 per mile (Table 2, page 26) are projected to cost 174% more than hardening an overhead feeder with larger conductors.

Response: Please note that per mile costs for the overhead feeder lateral hardening program cannot be derived from Table 3 as noted on footnote 15 associated with Table 3 and on 24(k) below. The projected per mile cost for the Overhead Lateral Hardening program is expected to be 25% higher than that of the Overhead Feeder Hardening program due to additional equipment typically located along branch lines than along main feeders. Things such as additional transformers, arrestors, downstream taps, etc. add additional expense, on the average, than those typically found on the mostly tangent poles located along feeder routes.

Respondent: Mark Cutshaw

Interrogatory No. 24(k)

k. Table 13 shows the average cost for Lateral hardening is $53,862. Compare this to the $689,655 per mile cost in Table 3. Please explain the difference in the cost per mile and the impact on the cost benefit of lateral hardening.

Response: Table 3 details the projected full project costs for Overhead Lateral Hardening jobs (engineering and construction). Table 13 details the 2022 costs associated with this Program. As noted on the plan, there are no planned construction activities in 2022 (only engineering), thus table 13 is reflective of projected engineering costs for the noted projects within the Overhead Lateral Hardening Program.

Respondent: Mark Cutshaw

Interrogatory No. 25(a)

25. Please see page 13 of SPP, Overhead Lateral Undergrounding, and respond to the following:

a. Describe exactly those facilities to be undergrounded (service, secondary, primary).

Response: Targeted overhead single phase laterals will be converted to underground beginning at the existing overhead fuse. All downstream primary, secondary, and service connections, for those customers whose meter can be adapted, will be converted to underground as well.

Respondent: Mark Cutshaw

Interrogatory No. 25(b)

b. Describe the cost impact to customers whose service may be undergrounded.

Response: Customers whose service may be undergrounded will be contacted by an FPUC representative or their designee with information about the conversion process, the meter base adapter, and any necessary easements. They will experience a planned outage at the time of conversion for which FPUC will follow all current practices for notifying customers of planned outage events. At this time there is expected to be no cost to customers.

Respondent: Mark Cutshaw

Interrogatory No. 25(c)

c. Describe how National Electric Code requirements and inspection of customer's facilities will impact undergrounding projects.

Response: The conversion of service to customers will be done without changing out the existing meter bases. Only the line side cables of the meter base are typically being updated/changed, not the meter base nor any of the load side connections/cables. This typically falls outside of NEC criteria for inspection.

In cases for which the service connection cannot be converted, the feed will be left overhead (60A services may not be converted) by leveraging an existing or installing a secondary service pole to use as a riser. As an alternative, the customer may also elect to hire an electrician to convert the meter base, at their expense, to a more modern meter base that can accept an underground service feed. In this case, the customers will be responsible for satisfying all necessary permits and inspections required by local codes and ordinances.

The decision to convert or not will typically flow as follows:

- Review the existing meter base locations in the field and decide if there is access for an underground service cable.
- If the existing meter base is a convertible model (many meter bases were manufactured such that an overhead or underground service cables could be used), a typical underground service riser could be used.
- If there is space available on the wall, then one of the service conversion adapters (meter base adaptor) would be used.

- If the meter base is an old style 60A model, or no conversion is possible (e.g., inadequate wall space), then it will be left as an overhead service unless the customer ops to hire an electrician ahead of time to replace their existing meter base.

Respondent: Mark Cutshaw

d. Describe how undergrounding laterals will be prioritized.

Response: FPUC implemented a systematic method of addressing and maintaining ongoing compliance with the requirements of the Rule. The Plan is grounded on a strategy that prioritizes feeders by leveraging the Risk Resiliency Model, focuses on feeders with the highest risk score, hardens the entire feeder backbone, hardens all multi-phase overhead laterals, and strategically undergrounds the worst performing single phase laterals.

As part of this process, FPUC:

- Collected data on the FPUC system and feeders.
- Risk ranked the feeders in a Risk Resiliency Model.
- Adjusted the deployment timing of the highest risk ranked feeders within the initial ten-year window based on several factors (e.g., potential DOT work, intent to start small in early years of the plan, finalizing remaining coastline exposure on section of a feeder, etc.).
- Calculated projected cost for identified projects based on cost estimates for programs of similar scope and known targeted units (mileage). In the cases for which specific mileage was not known, reasonable assumptions were drawn which were then updated as data was validated.
- Divided project deployment into multiple phases to minimize the impact to customer rates within a calendar year and to achieve the desired investment ramp-up strategy noted on the Plan.
- Allocated costs within the 10-year period by aligning the Engineering and Construction of feeders and laterals of the same feeder within same calendar years to ensure resource

efficiencies.

- Identified specific laterals to be hardened in the first year of the plan by establishing statistical thresholds and validating outage information against GIS data to group downstream fuses together.

Respondent: Mark Cutshaw

Interrogatory No. 25(e)

e. Provide a prioritized list of laterals to be undergrounded in the next 3 years.

Response: Please reference the previously provided "FPUC Model & Targets" worksheet from OPC's POD's 1-2, specifically the tab labeled "Targets" containing the prioritized list of laterals for 2022 and 2023. The 2024 targets will be design only targets located on other feeders as noted on the tab labeled "10YrPlan" within the same worksheet. The prioritization of those 2024 design-only laterals has not, however, been performed.

Respondent: Mark Cutshaw

Interrogatory No. 25(f)

f. Describe instances where hardening a lateral is not practical.

Response: When there is insufficient space to maintain required span lengths, guys lead lengths, clearances, etc. to meet hardening standards.

Respondent: Mark Cutshaw

Interrogatory No. 25(g)

g. On Page 28 of the SPP, one reason for undergrounding is when upgrading the overhead construction to NESC extreme wind standards is not practical or consistent with industry design standards. Explain and provide examples when designing upgrades are not consistent with industry design standards.

Response: Please see 25(f) above.

Respondent: Mark Cutshaw

Interrogatory No. 25(h)

h. Provide a cost benefit analysis for undergrounding laterals.

Response: Please reference Section 3.3 of FPUC's SPP detailing the costs and benefits of the Overhead Lateral Undergrounding Program.

Respondent: Mark Cutshaw

Interrogatory No. 26(a)

26. Please refer to Distribution Pole Inspections & Replacements, and answer the following:

a. Provide details on the Distribution Pole Inspection Program including frequency of inspection and inspection methods.

Response: Please reference Section 3.4 of FPUC's SPP detailing the Pole Inspection process.

Respondent: Mark Cutshaw

Interrogatory No. 26(b)

b. Provide the goal for the number of poles to be inspected each year.

Response: Please reference the previously provided "Appendix A" worksheet from OPC's POD's 1-2, specifically the tab labeled "Calculations" columns Q and R containing the targeted 3,963 inspections on a per year basis.

Respondent: Mark Cutshaw

c. Provide the actual number of poles inspected per year in the last 3 years.

Response: Please reference the previously provided "Appendix A" worksheet from OPC's POD's 1-2, specifically the tab labeled "Calculations" columns Q and R containing the 2019, 2020, and 2021 inspections.

Respondent: Mark Cutshaw

Interrogatory No. 26(d)

d. Provide the failure rate of poles inspected in the last 3 years.

Response: Please reference the previously provided "Appendix A" worksheet from OPC's POD's 1-2, specifically the tab labeled "Calculations" columns Q and R containing the 2019, 2020, and 2021 rejects (failed inspections).

Respondent: Mark Cutshaw

Interrogatory No. 26(e)

e. Does the inspection criteria for pole replacement as defined in NESC Table 261-1 use Grade B and Grade C strength factor when evaluating the poles?

Response: Poles are evaluated using Grade C construction, if replaced, Grade B construction is used.

Respondent: Mark Cutshaw

f. Is the inspection criteria for pole replacement as defined in NESC Table 261-1A based on extreme wind loading (Rule 250C) or based on ice and wind loading (Rule 250B)?

Response: Extreme wind loading, Rule 250C.

Respondent: Mark Cutshaw

Interrogatory No. 26(g)

g. When a distribution pole fails inspection and if FPUC uses trusses to extend life of poles, provide justification for the use of these trusses.

Response: FPUC does not currently use trusses to extend the life of poles that fail inspection. All poles failing the inspection criteria are flagged for replacements.

Respondent: Mark Cutshaw

Interrogatory No. 26(h)

h. When a pole is replaced, is it designed for extreme wind? If not, why not?

Response: Yes.

Respondent: Mark Cutshaw

Interrogatory No. 26(i)

i. Are all new poles designed for extreme wind?

Response: Yes.

Respondent: Mark Cutshaw

Interrogatory No. 26(j)

j. Describe the "enhancements" to the Distribution Pole Inspection & Replacement Program and their associated costs.

Response: Additional funding will be allocated to the program in future years to accelerate the replacement of poles that failed inspection. FPUC experienced an abnormally high rejection rate during the inspections that followed Hurricane Michael.

Respondent: Mark Cutshaw

Interrogatory No. 26(j)

k. Describe how the inspection program will "accelerate the replacement of wood distribution poles that have been targeted for replacement," as stated on page 13 of the SPP.

Response: Please see 26(j) above.

Respondent: Mark Cutshaw

Interrogatory No. 27(a)

27. Please see page 13 of SPP, Transmission System Inspection and Hardening, and respond to the following:

a. How many concrete structures remain on FPUC's 69 kV System?

Response: Please reference the previously provided "Appendix A" worksheet from OPC's POD's 1-2, specifically the tab labeled "Calculations" columns T and U noting the remaining 95 structures.

Respondent: Mark Cutshaw

Interrogatory No. 27(b)

b. How many 69kV structures were replaced in the last 3 years?

Response: FPUC has replaced 13 – 69 KV structures in the last 3 years.

Respondent: *Mark Cutshaw*

Interrogatory No. 27(c)

c. What was the total per year for replacement of 69kV structures?

Response: There were no 69 KV structure replacements during 2019 and 2020. All 13 – 69 KV structures were replaced in 2021.

Respondent: Mark Cutshaw

Interrogatory No. 27(d)

d. Provide documentation or test data that confirms the statement "concrete structures proven more resilient to extreme weather conditions," as stated on pages 13 through14 of the SPP.

Response: Please refer to FPUC's response to question 32.a. During previous hurricanes, FPUC has experienced failures of its 69KV wood poles while all concrete poles have remained standing and undamaged.

Respondent: Mark Cutshaw

28. Please see page 19 of the SPP and describe any flood mitigation programs contained in SPP.

Response: FPUC's SPP does not contain any new flood mitigation programs beyond those construction standards that are already in place.

Respondent: Mark Cutshaw

Interrogatory No. 29(a)

29. Regarding improvement of BIL on distribution poles, please answer the following:

a. What CFO level does FPUC strive for in its structures (tangent, and deadend)?

Response: 450 KV

Respondent: Mark Cutshaw

Interrogatory No. 29(b)

b. Does FPUC use IEEE 1410 Guide for Improving the Lightning Performance of Electric Power Overhead Distribution Lines?

Response: Yes.

Respondent: Mark Cutshaw

Interrogatory No. 29(c)

c. If FPUC does not use IEEE 1410 Guide, what design standards does FPUC employ for lightning mitigation?

Response: N/A

Respondent: Mark Cutshaw

Interrogatory No. 30(a)

30. Regarding the Overhead Lateral Undergrounding Program, please respond the following:

a) Confirm that the typical single-phase overhead lateral has 200 to 300 customers.

Response: The reference on page 28 of FPUC's SPP is in relation to all laterals, not just single-phase laterals.

Respondent: Mark Cutshaw

Interrogatory No. 30(a)i

i) If so, describe methods used to balance the load on the feeder.

Response: N/A

Respondent: Mark Cutshaw

Interrogatory No. 30(a)ii

ii) If so, describe methods to reduce voltage drop along a single-phase lateral with 200-300 customers.

Response: N/A

Respondent: Mark Cutshaw

Interrogatory No. 30(a)iii

iii) If so, describe the overhead over-current means to protect a single-phase lateral with 200 to 300 customers.

Response: N/A

Respondent: Mark Cutshaw

Interrogatory No. 30(a)iv

iv) If not, provide an estimate of the number of customers served by a typical single phase lateral.

Response: Typically, a single-phase lateral can provide service to one or more customers depending upon the conductor size, type customer and load requirements.

Respondent: Mark Cutshaw

Interrogatory No. 30(b)

b) Describe the methods used to prioritize the overhead lateral hardening.

Response: Please reference 25(d) above.

Respondent: Mark Cutshaw

Interrogatory No. 30(c)

c) Provide a prioritized list of overhead laterals to be hardened in the next 3 years.

Response: Please reference 25(e) above.

Respondent: Mark Cutshaw

Interrogatory No. 30(d)

d) Provide the societal impact for each analyzed scenario for the overhead laterals to be hardened in the next 3 years.

Response: Data made available to FPUC as part of the output from the Resiliency Risk Model is the overall Resiliency Risk Score by feeder and at the feeder level. Individual laterals were not analyzed through the model and were prioritized within the feeder as noted on 25(d) above.

Respondent: Mark Cutshaw

Interrogatory No. 30(e)

e) Do any of the laterals analyzed have societal cost savings greater than the proposed hardening costs? If so, provide such data.

Response: FPUC did not calculate societal cost savings for the analyzed laterals.

Respondent: Mark Cutshaw

Interrogatory No. 30(f)

f) For each of the overhead laterals to be hardened in the next 3 years provide the number of customers served by the lateral.

Response: Please reference Section 6.3 of FPUC's SPP detailing the number of customers served by the laterals identified in year 1 of the plan. The number of customers for laterals flagged for hardening in years 2 and 3 of the plan is not readily available.

Respondent: Mark Cutshaw

Interrogatory No. 30(g)

g) Provide a cost benefit analysis for overhead lateral hardening.

Response: Please reference 25(h) above.

Respondent: Mark Cutshaw

Interrogatory No. 31(a)

31. Please refer to Distribution Pole Inspection and Replacements and answer the following:

a. It is understood that FPUC is designing new poles for Rule 250C Extreme Wind and Grade B construction. Per NESC Table 261-1 poles designed for 250C should be replaced when the strength deteriorates to 75%. Explain why 67% is used in the FPUC inspection analysis?

Response: Please reference 2.b. in 20220049-EI OPC's 1st ROGs to FPUC (Nos. 1-6).

Respondent: Mark Cutshaw

Interrogatory No. 31(b)

b. FPUC's process states on page 30 of the SPP "poles identified by the contractor as being loaded at or above 100% are re-evaluated by FPUC engineers." Explain the basis for at or above100%. That is, 100% of what value?

Response: As a clarification this evaluation is in reference to additional load calculations performed by the contractor on poles with 3rd party attachment of ½" or larger and would be in addition to the regular inspection process. This value is representative of the Transverse Horizontal Loading of the pole.

Respondent: Mark Cutshaw

Interrogatory No. 31(c)

c. Explain why the analysis for pole replacement is conducted using Grade B construction and 60 mph winds instead of FPUC's design standard of Grade B and extreme wind (120 or 130 MPH).

Response: FPUC's design standard of Grade B with extreme wind is for new construction and replacements. This analysis should be applied to poles that were constructed prior to these standards being put in place. As FPUC completes large scale feeder improvements that bring greater sections of FPUC infrastructure up to standards it would be anticipated that analysis standards would be evaluated to align with construction standards.

Respondent: Mark Cutshaw

Interrogatory No. 31(d)

d. Provide the scope of work for the inspection protocol which may result in a pole being rejected based on other than ground line strength.

Response: The first step of the inspection process requires a visual inspection of the pole. If the pole was found to have a significant enough visual defect it would be rejected prior to the evaluation of ground line strength.

Respondent: Mark Cutshaw

Interrogatory No. 32(a)

32. Please refer to Transmission & Substation Resiliency and respond to the following:

a. Provide the number of failed concrete transmission poles on FPUC's system.

Response: There have been no failures of concrete transmission poles on FPUC's system.

Respondent: Mark Cutshaw

Interrogatory No. 32(b)

b. Confirm that the FPUC owned transmission line(s) from the FPL Nassauville Substation to State Route 200 are on separate structures.

Response: The two 138 KV transmission circuits from the FPL Nassauville Substation to SR 200 are on the same concrete poles with one exception. As the line makes a ninety degree turn at SR 200 it was necessary to use two concrete poles to ensure compliance with all codes.

Respondent: Mark Cutshaw

Interrogatory No. 32(c)

c. Provide the year that the double circuit 138kV line was built from Nassauville Substation to the FPUC Step Down Substation.

Response: The upgrade of this line occurred in 2001.

Respondent: Mark Cutshaw

Interrogatory No. 32(d)

d. If one of the two 138 KV lines between Nassauville Substation and the FPUC Step Down Substation is de-energized, can the remaining 138kV line on the same structures provide power to FPUC's load on the island?

Response: Yes.

Respondent: Mark Cutshaw

Interrogatory No. 32(e)

e. Provide the existing capacity of each of the 138kV circuits on the existing FPUC 138 kV double circuit line feeding Amelia Island.

Response: Either line has the capacity to adequately provide service to Amelia Island at maximum load even if the other line is de-energized.

Respondent: Mark Cutshaw

Interrogatory No. 32(f)

f. Provide the peak load on Amelia Island served by the 138kV transmission lines for the last 5 years.

Response: Peak load for Amelia Island for the last five years was 100.3 MW's.

Respondent: Mark Cutshaw

Interrogatory No. 33(a)

33. Please refer to the existing paper mill on Amelia Island, and answer the following:

a. Provide all operating agreements or MOUs which show the ability of FPUC to access co-generation capacity "at times of need."

Response: Other than the "Standard Offer Rate Schedules for Purchases from Cogenerators & Renewable Generating Facilities" which allows for the purchase of "as-available" energy, there are currently no other operating agreements or MOU's in place which shows the ability of FPUC to access co-generation capacity "at times of need". Should the line upgrade and substation construction be approved, the appropriate agreements will be developed.

Respondent: Mark Cutshaw

Interrogatory No. 33(b)

b. State the firm capacity that would be available to FPUC with the construction of the new substation and upgraded transmission line. If the capacity is not firm, describe any variability that may be inherent in the supply of power to FPUC from these resources.

Response: Information regarding the firm capacity details have not been developed at this time but it is anticipated that a minimum of 20 MW's of firm capacity will be available.

Respondent: Mark Cutshaw

Interrogatory No. 33(c)

c. Identify the entity that owns the existing substation at the mill(s) that does not meet FPUC's standards.

Response: The 69 KV interconnection with the mill occurs on a steel tower which includes a gang operated air break switch. WestRock owns the existing substation at the mill which is located approximately 250 feet beyond the interconnection and inside the secure mill area and is not readily accessible to FPUC..

Respondent: Mark Cutshaw

Interrogatory No. 33(d)

d. How will the proposed new FPUC substation built at or near the mills improve reliability of the mills?

Response: The intent for the new FPUC substation is to improve the resiliency and reliability for the FPUC customers based on the generating capacity at the mill and will not materially improve the reliability of the mill.

Respondent: Mark Cutshaw

Interrogatory No. 33(d)

e. If reliability is improved, will the mills be responsible for a portion of the transmission and substation upgrade costs? If so, how much?

Response: The mill will not be responsible for any costs. The new FPUC substation and transmission line upgrade are being installed to improve the resiliency and reliability for all the FPUC customers on the island utilizing the generating capacity at the mill.

Respondent: Mark Cutshaw

Interrogatory No. 33(f)

f. If the reliability is not improved, please explain how the reliability is decreased to the mills.

Response: The reliability to the mill will not change materially and will not be decreased.

Respondent: Mark Cutshaw

Interrogatory No. 34(a)

34. Please refer to the proposed 138kV transmission to Amelia Island, and respond to the following:

a. This line would provide an alternate feed to the island. If a transmission pole failed on the existing line, explain how restoration costs are reduced simply because there is an alternate feed to the island? That is the transmission pole still needs to be replaced.

Response: The additional line would provide for "reducing restoration costs and outage times associated with extreme weather events and enhancing reliability". Should the existing line fail due to any event, the additional line would reduce restoration costs by allowing additional planning, mobilization and material acquisitions to complete the repairs. Without the additional time, efficiencies in the restoration process would not be possible leading to additional expenses. The additional expenses would be due to the inability to plan efficiently, immediate/unplanned mobilizations, increased logistics/transportation cost and increased material cost based on urgent needs.

Respondent: Mark Cutshaw

Interrogatory No. 34(b)

b. If FPUC's data previously reported to the Commission following Hurricanes Hermine, Matthew, and Irma found no damage to hardened facilities (see page 34 of the SPP), explain why an alternate feed to the island is required.

Response: Hardened facilities have performed well in extreme weather events such as Hurricanes Hermine, Matthew and Irma, however, during Hurricane Michael there was some damage to hardened facilities of distribution feeders providing service to up to 2,500 customers. The additional transmission line would allow service to all the approximately 17,000 customers on Amelia Island to continue while cost effective repairs are made to the existing transmission line.

While the entire existing 138 KV transmission system has been "storm hardened" there is some chance that extreme weather, impact from vehicle/boat/airplane or vandalism could result in the loss of the critical feed to Amelia Island.

Respondent: Mark Cutshaw

c. FPUC has a plan to upgrade wood transmission poles to non-wood poles. If these upgrades greatly improve resiliency and reliability then why is an alternative feed to the island required at all.

Response: The existing 138 KV line provides for the off-island electrical supply to Amelia Island which is constructed using all concrete and steel "storm hardened" poles/structures for this purpose. The plan to replace wood transmission poles with non-wood poles is to address the on-island 69 KV transmission lines. The 69 KV transmission lines provide service to other substations on Amelia Island and the use of concrete poles in the transmission system is another excellent way to improve the resiliency and reliability on Amelia Island.

Respondent: Mark Cutshaw

Interrogatory No. 35(a)

35. Please refer to Grid Automation, also referred to as self-healing system, that uses sensors and algorithms to decide a series of switching operations to isolate the smallest section of line affected by an outage, and answer the following:

a. Does FPUC believe that these systems will be fully functional during a hurricane?

Response: While the "brains" for some of these systems is integrated within software systems installed in server rooms or control centers, grid automation systems rely on field equipment that is subjected to the same unpredictable conditions as the other assets that make up the electric grid. As such, catastrophic damage at a location associated with an asset that plays a critical role in a grid automation system's functionality would render the use of that particular asset for automated or remote restoration purposes useless until such asset is repaired. This statement is true during extreme weather conditions that may cause an uprooted tree from outside the right of way to damage the asset or during clear weather conditions in which the asset may be damaged as part of a vehicular accident. FPUC agrees with the Commission's findings during their 2018 review of Florida's Electric Utility Hurricane Preparedness and Restoration Actions report that "no amount of preparation can eliminate outages in extreme weather events" however, FPUC can play a part in implementing programs that reduce outages and subsequent outage durations. Grid automation systems are one such program that leverages the use of technology to achieve this objective and have been successfully utilized by other larger utilities.

Respondent: Mark Cutshaw

Interrogatory No. 35(b)

b. Does FPUC believe that these systems will be fully functional after a hurricane?

Response: Please see 35(a) above.

Respondent: Mark Cutshaw

Interrogatory No. 35(c)

c. Explain how these systems will accelerate restoration from a major storm such as a hurricane when multiple feeders are out of power

Response: More modern systems can be configured to leverage real-time system information to make real-time decisions on load shifting across multiple feeders. Depending on damage location, real-time load at the time of the outage on both the lost section of feeder and available capacity on unaffected feeders, and pre-programmed logic will impact how much of the load can be transferred to other areas of the grid. Following an extreme weather event, the communications and control functionality of these systems allow for a distribution operator to remotely operate a field device thus eliminating travel time between field devices and accelerating restoration.

Respondent: Mark Cutshaw

d. Confirm that the loss of communication to a device within the decision tree of a self-healing system group of interconnected feeders negates the operation of the self- healing system. If you disagree, please provided a detail explanation of why.

Response: There are multiple variations and configuration alternatives associated with grid automation devices which vary by vendor. Early systems had localized communication between associated devices in which failure to communicate between devices would cause a failure of operation. While FPUC does not own nor operate any of these systems, it is our understanding that certain vendors today offer systems that can be configured to leverage real time system information to make decisions on load shifting across multiple feeders. Some of these features would account for failed communication to a particular device to trigger an alternate decision logic. FPUC has not settled on any equipment or software vendor, device communication method, or decision logic for its grid automation system. This will be evaluated over the coming years and included in future SPP updates as appropriate.

Respondent: Mark Cutshaw

Interrogatory No. 36(a)

36. Regarding FPUC's SCADA systems in the NE and NW, please respond to the following:

a. Does FPUC contemplate using the SPP to fund commissioning and/or upgrades to the SCADA systems?

Response: FPUC does plan to consider this in more detail in the future as grid automation systems are implemented.

Respondent: Mark Cutshaw

Interrogatory No. 36(b)

b. Explain why the FPUC allowed the NW Division to previously decommission the SCADA system.

Response: As components of the NW SCADA began to fail, FPUC realized that the equipment was obsolete and not worth repairing.

Respondent: Mark Cutshaw

Interrogatory No. 36(c)

c. What year was the NW SCADA system decommissioned?

Response: The NW SCADA system was decommissioned in 2015.

Respondent: Mark Cutshaw

Interrogatory No. 36(d)

d. For each of these analyses or studies developed in the last 10 years to install a new SCADA system in the NW Division, please explain why funding was not made available for this project.

Response: Please refer to FPUC's response to question 36.b. FPUC's believes in using its financial resources efficiently. Therefore, investing in repairing obsolete SCADA components is not financially efficient. Additionally, no detailed studies have been completed that would allow decisions to be made on the installation of a new SCADA system. However, a SCADA system will provide benefits to the restoration process and will be analyzed in the future.

Respondent: Mark Cutshaw

Interrogatory No. 37(a)

37. Regarding Vegetation Management, please answer the following:

a. Provide the annual cost difference from FPUC's 2014 3-year feeder and 6-year lateral vegetation management program and the program recommended by Davey Resources.

Response: The annual cost difference is $685,000.

Respondent: Mark Cutshaw

Interrogatory No. 37(b)

b. Provide outage data for vegetation caused outages from 2014 to the present.

Response: Please refer to the Excel file submitted on April 12, 2022 and labeled "Combined Outage data (Excel)". This file contains all the outage data used to develop the SPP and it includes all vegetation caused outages.

Respondent: Mark Cutshaw

Interrogatory No. 37(c)

c. Provide the year the 3-year cycle program began.

Response: Current 3 year cycle began 2008.

Respondent: Mark Cutshaw

Interrogatory No. 37(d)

d. What changes, if any, has FPUC made regarding overhanging vegetation?

Response: FPUC has always considered overhanging vegetation a hazardous condition and recommends removal whenever possible.

Respondent: Mark Cutshaw

Interrogatory No. 37(e)

e. Once the overhang vegetation is removed will the vegetation maintenance cost be reduced in subsequent cycles? If so by how much?

Response: Overhanging vegetation management is currently part of FPUC's vegetation management process and it is assumed to be a continual process which will not impact cost in the future.

Respondent: Mark Cutshaw

Interrogatory No. 37(f)

f. Has FPUC implemented a hazard tree program and is the cost of this program imbedded in the vegetation management program? Provide separate costs for the hazard tree program.

Response:

FPUC currently evaluates danger trees "hazard trees" when reported and removes them whenever possible. The cost for removals is not captured separately, however, FPUC does report an estimated cost for danger tree removals in Part II of our annual Reliability Report to the Florida Public Service Commission. The 2019-2021 average consolidated cost estimate for danger tree removal is $243,800.00.

Respondent: Mark Cutshaw

Interrogatory No. 38(a)

38. Please refer to Vegetation Management costs, and please respond to the following

a. Other vegetation management costs may include mid-cycle trimming, hot spot trimming, trimming/clearing required from storm damage. Are these vegetation management costs contained in the SPP?

Response: FPUC does not currently separate hot spot and mid-cycle trimming costs from general vegetation management cost. Storm related vegetation management is typically captured separately.

As previously mentioned, there are some vegetation management cost included in base rates with the remainder to be included in the SPPCR. Additional discussions will need to occur to determine the most appropriate manner in which recovery will occur.

Respondent: Mark Cutshaw

Interrogatory No. 38(b)

b. If so, provide a separate estimate for these activities.

Response: See 38(a).

Respondent: Mark Cutshaw

Interrogatory No. 38(c)

c. If not, describe safeguards to prevent vegetation management costs from being captured in both rate base O&M charges and SPPCRC charges.

Response: See 38(a).

Respondent: Mark Cutshaw

39. In preparing your SPP, what measures have you implemented, or do you intend to implement in order to drive efficiencies in the costs to be incurred under the SPPCRC.

Response: Included in the FPUC SPP filing is one Full Time Equivalent (FTE) position that will be responsible for continued development, monitoring and administration. This position will be responsible for the FPUC SPP projects, scheduling and cost control/data collection necessary for the success of the program as well as documentation necessary for the Cost Recovery for the FPUC SPP.

Respondent: Mark Cutshaw

Interrogatory No. 40

40. Please describe how the O&M efficiency measures you announced or discussed in public or private to investors or to analysts apply to O&M expenditures that you intend and/or expect to make under the SPP. Please identify the documents describing such measures and explaining how they apply to SPP programs and projects.

Response: FPUC objects to this request to the extent that it is beyond the scope of discovery in this proceeding, and not likely to lead to the discovery of admissible evidence. Notwithstanding, and without waiving this objection, FPUC states that there have been no O&M efficiency measures announced or discussed in public or private to investors or to analyst.

Respondent: Mark Cutshaw

Interrogatory No. 41

41. Are the O&M expenditures you make that are subject to pass-through clause recovery in Florida included in, or subject to, any company-wide cost control or efficiency measure that you have publicly announced or discussed in public or private to investors or to analysts?

Response: FPUC objects to this request to the extent that it is beyond the scope of discovery in this proceeding, and not likely to lead to the discovery of admissible evidence. Notwithstanding, and without waiving this objection, FPUC states that there has been no information announced regarding O&M expenditures or pass-through clause recovery in Florida discussed in public or private to investors or to analyst.

Respondent: Mark Cutshaw

Interrogatory No. 42

42. Are the type of storm restoration costs that are included in or considered in your cost and benefit comparisons required by Rule 25-6.30, F.A.C., subject to your company-wide cost control or efficiency measure(s)? If yes, please identify all documents describing how such measures apply to storm restoration costs.

Response: There are currently no documents that address how the SPP programs and cost are subject to company-wide cost control and efficiency measures. However, it is anticipated that these projects will be reviewed along with all other construction projects.

Respondent: Mark Cutshaw

43. How do you reconcile representations to investors about growth in capital spending related to SPP programs and projects with the rate impacts of such programs and projects?

Response: FPUC objects to this request to the extent that it is beyond the scope of discovery in this proceeding, and not likely to lead to the discovery of admissible evidence. Notwithstanding, and without waiving this objection, FPUC states that there has been no information announced regarding growth in capital spending related to SPP programs and projects discussed in public or private to investors or to analyst.

Respondent: Mark Cutshaw

Interrogatory No. 44

44. How are projected rate impacts from SPP projects and programs factored into the projected SPP spending plans that you share with investors?

Response: FPUC objects to this request to the extent that it is beyond the scope of discovery in this proceeding, and not likely to lead to the discovery of admissible evidence. Notwithstanding, and without waiving this objection, FPUC states that there has been no information announced regarding rate impacts from SPP programs and projects discussed in public or private to investors or to analyst.

Respondent: Mark Cutshaw

Interrogatory No. 45

45. In determining how to deploy capital investment in your pending SPP, please describe the steps that were taken to consider customer rate impacts. As a part of any description you undertook, please describe the role that customer rate impacts play compared to your investor- driven financial goals such as the increasing adjusted earnings per share expectations at your publicly traded corporate entity level and yearly expected growth in dividend per share.

Response: As this is the initial SPP, FPUC is particularly aware of the potential benefits, as well as the anticipated financial impact for our customers based on the SPP programs. As such, the Company has taken the approach to phase in the programs to minimize the impact of compliance. FPUC is looking at all aspects that compliance with the SPP will have on the company financials but has not undertaken any study to compare customer rate impacts with investor driven financial goals.

Respondent: Mark Cutshaw

46. Since you began developing your SPP, please identify each instance where you expressly decided not to deploy capital for an SPP Program or project because it would have had too great an impact on your customers' rates in any single year.

Response: The goal of developing the SPP is to comply with Section 366.96 (1)(c), F.S., which provides:

> It is in the state's interest to strengthen electric utility infrastructure to withstand extreme weather conditions by promoting the overhead hardening of electrical transmission and distribution facilities, the undergrounding of certain electrical distribution lines, and vegetation management.

Consistent with this requirement, FPUC used a systematic method to address and maintain ongoing compliance with the requirements included in Section 366.96 F.S and FPSC Rule 25-6.030 F.A.C. Additionally, FPUC considered a phased in approach to the programs in order to not unduly burden FPUC customers.

Respondent: Mark Cutshaw