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Commission Conference Agenda
March 7, 2023

Item 1

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FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 23, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Office of Industry Development and Market Analysis (Day, Deas, Temprano, Fogleman) CH
Office of the General Counsel (Sparks, Jones) AEH

RE: Application for Certificate of Authority to Provide Telecommunications Service

AGENDA: 3/7/2023 - Consent Agenda - Proposed Agency Action - Interested Persons May Participate

SPECIAL INSTRUCTIONS: None

Please place the following Applications for Certificate of Authority to Provide Telecommunications Service on the consent agenda for approval.

DOCKET NO.	COMPANY NAME	CERT. NO.
20230016-TX	Rapid Fiber Internet, LLC	8978
20220200-TX	Cirion Technologies Solutions, LLC	8979

The Commission is vested with jurisdiction in this matter pursuant to Section 364.335, Florida Statutes. Pursuant to Section 364.336, Florida Statutes, certificate holders must pay a minimum annual Regulatory Assessment Fee if the certificate is active during any portion of the calendar year. A Regulatory Assessment Fee Return Notice will be mailed each December to the entities listed above for payment by January 30.

Item 2

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 23, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Office of the General Counsel (Rubottom, Jones) SMC
Division of Economics (Guffey) JGH
Division of Engineering (Ellis, King, Thompson) TB

RE: Docket No. 20200181-EU – Proposed amendment of Rule 25-17.0021, F.A.C., Goals for Electric Utilities.

AGENDA: 03/07/23 – Regular Agenda – Rule Proposal – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

RULE STATUS: Proposal May Be Deferred

SPECIAL INSTRUCTIONS: None

Case Background

Rule 25-17.0021, Florida Administrative Code (F.A.C.), Goals for Electric Utilities, implements the Commission's statutory mandate to adopt goals for electric utilities, approve utility plans, and collect periodic reports from utilities related to promoting efficiency and conservation of electric energy as provided in Sections 366.80-366.83 and 403.519, Florida Statutes (F.S.), known together as the Florida Energy Efficiency and Conservation Act (FEECA). The Commission is required by FEECA to establish goals at least once every five years for utilities subject to FEECA. The utilities are required to develop plans and programs to reach those goals and submit them for approval by the Commission.

The six electric utilities currently subject to FEECA are Florida Power & Light Company (FPL), Duke Energy Florida, LLC (Duke), Tampa Electric Company (TECO), Florida Public Utilities Company (FPUC), JEA, and Orlando Utilities Commission (OUC).

In the 2019 goal-setting proceeding, the Commission chose to continue the goals established by its 2014 goal-setting decision for the period 2020-2024 and directed staff to review the FEECA process for potential updates and revisions.[1] This rulemaking was initiated at the direction of the Commission following the 2020 DSM plan-approval proceeding.[2]

FEECA's Requirements

The Legislature adopted FEECA in order to promote four key priorities: (1) reducing the growth rates of weather-sensitive peak demand and electricity usage, (2) increasing the efficiency of the production and consumption of electricity and natural gas, (3) encouraging demand-side renewable energy systems, and (4) conserving expensive resources, particularly petroleum fuel.[3] The Legislature emphasized that it is critical to utilize "efficient and cost-effective" conservation systems.[4]

The Legislature set forth in Section 366.82, F.S., appended as Attachment C, specific statutory guidelines for the Commission to implement FEECA's objectives through the establishment of conservation goals for utilities and approval of utility plans to meet those goals.

The Commission's goal-setting and plan-approval proceedings are conducted pursuant to Sections 120.569 and 120.57, F.S., affording all parties whose substantial interests are affected the opportunity to participate in discovery, to offer testimony and other evidence, and to conduct cross-examination of witnesses at the administrative hearings.

FEECA's Goal-Setting Process for Electric Utilities

Section 366.82(2), F.S., directs the Commission to "adopt appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems." It further provides that the Commission should specifically include goals designed to increase the conservation of expensive resources, such as petroleum fuels; to reduce and control the growth rates of electric consumption; to reduce the growth rates of weather-sensitive peak demand; and to encourage development of demand-side renewable energy resources.

The Commission is required by Section 366.82(3), F.S., in the process of developing conservation goals, to "evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures." The Commission is further directed by that section, in establishing the goals, to take into consideration:

(a) The costs and benefits to customers participating in the measure.
(b) The costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions.

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[1] Order No. PSC-2019-0509-FOF-EG, *Final Order Approving Numeric Conservation Goals*, issued on November 26, 2019, in Docket Nos. 20190015-EG, 20190016-EG, 20190017-EG, 20190018-EG, 20190019-EG, 20190020-EG, 20190021-EG, *In re: Commission review of numeric conservation goals.*
[2] *See* Docket Nos. 20200053-EG, 20200054-EG, 20200055-EG, 20200056-EG, 20200060-EG.
[3] *See* Section 366.81, F.S.
[4] *Id.*

(c) The need for incentives to promote both customer-owned and utility-owned energy efficiency and demand-side renewable energy systems.
(d) The costs imposed by state and federal regulations on the emission of greenhouse gases.

As mentioned above, the Commission is required to review the goals at least every five years, and the Commission may change the goals for reasonable cause.[5]

FEECA's Electric Utility Plan Approval Process

Section 366.82(7), F.S., addresses the Commission's process for approving utility plans and programs to meet the conservation goals. Utility programs may include any measure "within the jurisdiction of the [C]ommission which the [C]ommission finds likely to be effective." In approving plans and programs for cost recovery, the Commission "shall have the flexibility to modify or deny plans or programs that would have an undue impact on the costs passed on to customers." When a utility completes its plans and programs, the Commission is required to determine what further goals, plans, and programs are warranted and adopt them.[6]

Other Commission Rules Implementing FEECA

The Commission rules implementing FEECA are located in Chapter 25-17, F.A.C., including particular rules that apply to electric utilities promoting conservation through DSM efforts. FEECA's emphasis on utilizing cost-effective energy conservation is codified in Rule 25-17.008, F.A.C., which prescribes cost-effectiveness data reporting formats for demand-side conservation programs. *See also* Rule 25-17.001, F.A.C. Rule 25-17.015, F.A.C, contains the filing requirements for cost recovery for approved conservation efforts through the Energy Conservation Cost Recovery (ECCR) proceedings.

Procedural Issues

A Notice of Rule Development for Rule 25-17.0021, F.A.C., appeared in the November 24, 2020, edition of the Florida Administrative Register, Vol. 46, No. 229. No other Commission rules implementing FEECA were noticed for rule development as part of this rulemaking.

Staff rule development workshops were held on January 14, 2021,[7] May 18, 2021,[8] and on November 30, 2022.[9] Participants at the workshops included: Duke, FPL, Gulf Power Company, TECO, FPUC, JEA, the Office of Public Counsel (OPC), City of Miami Beach, City of St. Petersburg, Orange County, Broward County, Advanced Energy United (AEU) (formerly known as Advanced Energy Economy), American Council for an Energy Efficient Economy (ACEEE), Catalyst Miami, Ceres, the CLEO Institute (CLEO), Connected in Crisis Coalition, E4TheFuture, Environmental Coalition of Southwest Florida (ECOSWF), Family Action Network Movement, Florida Conservation Voters, Florida Rising, IGT Solar, Johnson Consulting Group, League of United Latin American Citizens (LULAC), Miami Climate Alliance, NAACP Florida State Conference, Net Plus Solar Power Group, Real Building Consultants, Solar United Neighbors of

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[5] Section 366.82(6), F.S.
[6] Section 366.82(6), F.S.
[7] Document No. 13530-2020.
[8] Document No. 03755-2021.
[9] Document No. 11025-2022.

Florida, Southeast Energy Efficiency Alliance (SEEA), Southeast Sustainability Directors Network (SSDN), Southern Alliance for Clean Energy (SACE), Southface Institute (Southface), Synapse Energy Economics, Tampa Bay Energy Efficiency Alliance, Vote Solar, and various private individuals.

Post-workshop comments were filed after each workshop. Prior to the third workshop, staff published a revised draft of the rule for discussion and consideration, and post-workshop comments were filed with comments on that draft by: Duke, FPL, TECO, ACEEE, AEU, Catalyst Miami, Alianza for Progress, Florida Conservation Voters, Healthy Gulf, Florida Clinicians for Climate Action, Broward Climate Alliance, Florida Immigration Coalition, and Opportunity for All Floridians, CLEO, a group of Florida faith leaders, Google Nest, LULAC, ECOSWF, Miami-Dade County, OPC, ReThink Energy Florida, SACE, Sierra Club, Southface, and Vote Solar. Additionally, over 2,000 correspondence documents with comments on this rule development have been placed in the docket from various individuals and utility customers.

This recommendation addresses whether the Commission should propose the amendment of Rule 25-17.0021, F.A.C., Goals for Electric Utilities. The Commission has jurisdiction pursuant to Sections 120.54, 366.05, and 366.82, F.S.

Discussion of Issues

Issue 1: Should the Commission propose the amendment of Rule 25-17.0021, F.A.C., Goals for Electric Utilities?

Recommendation: Yes. The Commission should propose the amendment of Rule 25-17.0021, F.A.C., as set forth in Attachment A. The Commission should also certify that Rule 25-17.0021, F.A.C., is a rule the violation of which would be a minor rule violation pursuant to Section 120.695, F.S. (Rubottom, Thompson, Guffey)

Staff Analysis: Rule 25-17.0021, F.A.C., implements FEECA's requirement that the Commission adopt appropriate efficiency and conservation goals for electric utilities and approve utility plans and programs designed to meet those goals. The purpose of this rulemaking is to improve the administrative efficiency and overall transparency of the Commission's goal-setting process.

The long-standing goal-setting process has featured annual goals proposed by utilities based upon the aggregated demand and energy savings of individual conservation measures. These measures can include the replacement of existing technology with more energy efficient equipment that results in electric demand and energy savings. Once goals are approved by the Commission, utilities propose conservation plans that bundle measures into programs to be offered to customers. For example, multiple lighting technology measures can be bundled into a lighting program. The existing rule, however, does not require a utility to include measures used in its aggregated proposed goals in the programs ultimately offered to customers. This results in a disconnect in the Commission's annual review of utility performance because demand and energy savings achieved from customer participation in approved programs is compared to the measure-based goals established by the Commission.

Additionally, the goal-setting process under the existing rule provides the utilities with discretion to submit their proposed annual goals based upon only their preferred cost-effectiveness tests. This practice has resulted in limiting the breadth of information and data on the cost-effectiveness of conservation measures and programs that the Commission can consider as it develops and establishes goals.

Staff's recommended rule amendments make two primary revisions to the goal-setting process designed to address the concerns outlined above: (1) goals would be based upon projected savings from potential programs offered to customers rather than upon aggregated savings from individual conservation measures; and (2) utilities would be required to provide projected savings or goals developed under two cost-effectiveness scenarios, rather than a single cost-effectiveness test, in order to provide a more robust record of evidence. Specifically, staff's objective with the recommended amendments is to bring into the goal-setting phase a greater focus on potential conservation programs that could be offered to customers in order to reach a utility's approved goals.

Staff believes that the recommended amendments to the rule, as set forth in Attachment A, would improve the transparency and efficiency of the goal-setting and plan-approval processes, as well as ensure that the Commission can gather and analyze information necessary and relevant to fulfilling FEECA's statutory mandate to utilize cost-effective efficiency and conservation systems.

Summary and Analysis of Recommended Amendments

Staff's recommended amendments to Rule 25-17.0021, F.A.C., will be discussed subsection-by-subsection through the rule as set forth in Attachment A. For each subsection, the discussion will first present a summary and explanation of the recommended amendments, then a summary of comments related to that subsection as received from stakeholders and staff's recommendations on those comments.

As a threshold matter, this recommendation addresses the comments staff believes to be within the scope of Rule 25-17.0021, F.A.C.[10] In addition to the comments discussed below, Duke, FPL, and TECO ("Utilities") provided comments in support of staff's recommended rule amendments. In general, the Utilities agreed that the amendments would provide greater transparency, increase administrative efficiency in the goal-setting and plan-approval processes, and provide the Commission with additional information and flexibility to meet FEECA's requirements to balance costs and benefits.

Additionally, some stakeholders submitted comments on other matters, such as supply-side and transmission efficiency measures; amending Rule 25-17.008, F.A.C., to adopt a "modified Total Resource Cost Test" that includes a "societal adder" to account for non-energy benefits; replacing the Commission's Cost Effectiveness Manual with a National Standard Practice Manual; and the creation of a DSM Working Group comprised of utilities and other interested stakeholders. This recommendation does not address those issues because staff believes those comments are outside the scope of this rulemaking.

The majority of non-utility individuals and groups that participated in the rule development workshops and submitted comments on the draft rule, including individuals who submitted correspondence documents, were closely aligned in their basic positions and suggestions. Because their comments were largely similar in substance, those commenters will be referred to collectively as "Stakeholders" for purposes of discussing their comments.[11]

Subsection (1) Recommended Amendments

Subsection (1) of the recommended amended rule addresses the frequency, nature, and basis of the goals the Commission will set for electric utilities. Recommended amendments clarify language related to the evidence upon which the Commission will base the FEECA goals and how the Commission will gather the information necessary to develop and assess potential goals. In particular, paragraph (1)(a) codifies the statutory requirement that the Commission shall evaluate the technical potential of available measures, as required by Section 366.82(3), F.S., and the word "programs" was added in paragraph (1)(b) to clarify that the estimate of reasonably

[10] As stated above, only Rule 25-17.0021, F.A.C., was included in the notice for rule development. Thus, comments pertaining to other rules or to matters outside the scope of this rule are not addressed in this recommendation.
[11] Some stakeholders, including SACE, LULAC, ECOSWF, AEU, CLEO, Southface, and Vote Solar, contributed to the creation and filing of a consensus draft revision of the rule that summarized the proposals of a majority of commenters. Staff considered this consensus draft along with all other comments filed in the docket.

achievable savings should be focused on potential DSM programs. Other recommended amendments to subsection (1) include:

- Language related to the frequency of goal-setting procedures ("at least once every five years") was moved to this subsection from subsection (2).

- Deleted the word "numerical" to allow the Commission the flexibility to set non-numerical goals if appropriate under FEECA.

- Deleted language related to the specific objectives of the goals because it restated language existing in Section 366.82(2), F.S.

- General updates to language for clarity.

Summary of Comments Received & Staff Response

Stakeholders suggest that the rule should include some consideration or mechanism to increase participation in DSM programs among low-income customers. Stakeholders assert that the DSM goals established by the Commission should include separate and discrete DSM goals for low-income customers. They point out that because low-income customers generally spend a higher percentage of household income on energy, they would experience a significant benefit from the lower electricity bills associated with DSM program participation. They further point out that the needs and market barriers unique to low-income customers negatively affect their ability to participate in DSM measures. Therefore, Stakeholders want the Commission to set discrete kilowatt (KW) and kilowatt-hour (KWH) savings goals for low-income customers that would make it easier for low-income customers to participate in utility-sponsored DSM programs. Suggestions for such goals also included requiring a minimum percentage of utilities' DSM spending to be allocated for low-income programs.

Under the amended rule as recommended, the Commission will establish goals for Residential customers based on an analysis of the technical potential of available measures and cost-effective savings reasonably achievable through DSM programs, as required by Section 366.82(3), F.S. Staff notes, however, that the residential market segment is not differentiated by income levels and thus, low-income customers are already included in the technical potential and cost-effectiveness analysis for this market segment. Therefore, staff believes it unnecessary to require distinct goals for a customer class included within the Residential market segment.

Further, staff believes that codifying distinct low-income goals would unnecessarily restrict the discretion given to the Commission by statute. As Stakeholders observe, low-income customers have higher market barriers affecting participation in DSM measures. FEECA contemplates overall conservation goals, DSM plans and programs designed to meet those goals, and particular DSM measures included in those plans and programs. *See* Section 366.82(2)-(3), F.S. Thus, if the Commission sets discrete goals for low-income customers, then discrete plans, programs, and measures for low-income customers would be required to meet those goals under FEECA. However, if low-income customers are considered as part of the Residential market segment for goal-setting purposes, the Commission could consider potential low-income DSM measures as part of a portfolio within a larger Residential plan or program, allowing greater flexibility in how utilities can account for, and the Commission can consider, the particular needs of low-income customers. The Commission has a history of doing just that by directing utilities to use a "portfolio approach" that allows low-income DSM measures to be considered as part of a "bundle" with cost-effective programs.[12]

For these reasons, staff does not recommend the Commission include provisions related to separate low-income goals in the rule.

Subsection (2) Recommended Amendments

Subsection (2) of the recommended amended rule codifies and clarifies the technical potential study to be conducted by electric utilities and filed for the Commission to evaluate in developing goals as required by FEECA in Section 366.82(3), F.S.

Staff's recommended amendments to this subsection clarify that the technical potential study should focus on DSM measures associated with particular major end-use categories in the Residential and Commercial/Industrial Market Segments. The assessment of major end-use categories was moved to this subsection from subsection (3) of the existing rule, and the lists of major end-use categories were amended for consistency and clarity. Of particular note, the "Renewable/Natural gas substitutes for electricity" category was deleted to avoid confusion regarding substitution between electricity and natural gas. Because both electric and gas energy resources are covered by FEECA with separate goals, staff believes that electric utilities should not be encouraged to meet their own FEECA goals by undermining FEECA's priorities for natural gas conservation, and vice versa. In general, staff believes load-building DSM measures—such as those substituting one FEECA resource for another—should not be encouraged as measures to meet FEECA goals.

Additional recommended amendments to subsection (2) are:

- Added language clarifying that the Commission has flexibility to set the filing schedule for the technical potential study in an order establishing procedure.

- Required the utilities to assess "the full potential of all available demand-side conservation and efficiency measures" mirroring the statutory language in Section 366.82(3), F.S.

- Moved language related to frequency of goal-setting procedures ("at least once every five years") from this subsection to subsection (1).

- Moved language related to the Commission's discretion to review and modify goals to subsection (5) of the amended rule in order to keep the focus of subsection (2) on the technical potential study.

[12] *See* Order No. PSC-14-0696-FOF-EU, *Final Order Approving Numeric Conservation Goals*, at p. 27, issued on December 16, 2014, in Docket Nos. 130199-EI, 130200-EI, 130201-EI, 130202-EI, 130203-EI, and 130204-EI, *In re: Commission review of numeric conservation goals.* (directing utilities to consider low-income customers using a "portfolio approach of information coupled with cost-effective incentives to address this market").

Summary of Comments Received & Staff Response

Stakeholders suggest that "efficient electricity substitutes for natural gas" should be added as an end-use category considered in the technical potential study, arguing that electricity is a more efficient energy source than natural gas and would thus provide a net gain in conservation of resources. Stakeholders also suggest adding an additional end-use category, such as "other," as a catch-all category to allow the Commission to consider efficiency measures related to emerging technologies—such as electric vehicles—that do not fit under any of the end-use categories listed in the subsection.

As stated above, staff believes load-building DSM measures—such as those substituting natural gas consumption for electricity—should not be encouraged as viable measures to meet FEECA goals. Thus, staff recommends that the Commission not include in subsection (2) the addition of an end-use category encouraging such substitution.

Additionally, staff recommends that the Commission not include a catch-all "other" category because it would not provide sufficient guidelines for implementation or enforcement. As such, it could be construed as a broad claim of authority beyond what FEECA grants. Staff believes the categories contained in the recommended amended rule are sufficient to allow the Commission to consider the full technical potential of all available DSM measures, as required by FEECA in Section 366.82(3), F.S., without foreclosing the future consideration of available measures that may not fit neatly into the end-use categories enumerated in the rule.

Subsection (3) Recommended Amendments

Subsection (3) of the recommended amended rule focuses on cost-effectiveness data and prescribes information to be provided by utilities that will enable the Commission to consider the costs and benefits of potential DSM programs and the potential costs passed on to customers, as required by FEECA in Sections 366.81 and 366.82(3), (7), F.S.

In particular, each electric utility is required to file proposed DSM goals developed using the technical potential study in subsection (2). In addition to the proposed goals, each electric utility must file DSM goals developed under two cost-effectiveness scenarios: in one scenario, the goals must include potential DSM programs that pass the Participant Test and the Rate Impact Measure (RIM) Test; in the other scenario, the goals must include potential programs that pass the Participant Test and the Total Resource Cost (TRC) Test.[13] In each scenario, the DSM programs may include individual DSM measures that do not pass the cost-effectiveness tests but the program itself, comprised of various measures, must pass the combination of tests prescribed for that scenario.

Staff believes that the two cost-effectiveness scenarios discussed above will provide the Commission with a broad range of information related to the costs and benefits of available DSM measures—information that will equip the Commission to comply with FEECA's requirements to consider the costs and benefits of those measures on participants, non-

[13] For a detailed description of each cost-effectiveness test, see Rule 25-17.008, F.A.C., which incorporates the Commission's Cost Effectiveness Manual for Demand Side Management Programs and Self Service Wheeling Proposals (Cost Effectiveness Manual).

participants, and the general body of ratepayers as a whole, as required by FEECA in Section 366.82(3), F.S., without relying on the outcome of a single cost-effectiveness test.

The recommended amended language also provides that goal projections must provide estimated annual demand and energy savings from potential DSM programs and estimated annual program costs. This will allow the Commission to consider the benefit of overall savings from DSM programs in light of the overall cost of the programs.

The cost-effectiveness information provided through the two scenarios and related estimated annual program costs will give the Commission at the goal-setting stage information relevant to its statutory mandate to assess whether potential DSM plans and programs proposed to meet the goals may have an undue impact on rates as required by FEECA in Section 366.82(7), F.S. Additionally, the recommended amendments will allow the Commission to remain flexible to respond appropriately to the availability of evolving technologies and to the shifting market conditions as they exist at the time of each goal-setting proceeding.

Additional recommended amendments to subsection (3) clarify that the schedule for each utility to file proposed goals will be set by the Commission's order establishing procedure, and they make general updates to the language for clarity and specificity.

Summary of Comments Received & Staff Response

Comments on subsection (3) addressed two principal areas: first, the rule's prescribed cost-effectiveness analysis and particularly the RIM Test; and second, how the Commission should address free ridership concerns.

Cost Effectiveness & RIM Test

Stakeholders suggest that the Commission exempt DSM programs designed for low-income customers from its cost-effectiveness analysis.

Staff believes that exempting DSM programs for low-income customers from cost-effectiveness analysis violates FEECA's directives to analyze cost effectiveness, particularly its requirement that the Commission must consider the costs and benefits of potential DSM measures as it establishes goals for utilities. *See* Section 366.82(3), F.S. Thus, staff did not treat such programs differently in its recommended amendments.

Stakeholders also argue that the Commission should amend the rule to eliminate the RIM Test from its analysis of cost-effectiveness. They assert that the RIM Test treats customer bill savings resulting from efficiency measures as lost utility revenue, and thus as a cost rather than a benefit. Stakeholders also argue that the actual impact on rates resulting from lost revenues is speculative and highly dependent on other market factors, and that because the test only indicates the direction of resulting pressure on rates (upward or downward), the RIM Test thus provides no meaningful information for the Commission to assess cost effectiveness. Stakeholders argue that although the RIM Test may limit cross-subsidization of utility-led DSM measures that put upward pressure on rates, this concern is mitigated by simultaneous downward pressure on rates resulting from DSM benefits such as reduced fuel use, efficient consumption, and avoided generation investments. Further, Stakeholders contend that the RIM Test favors DSM measures that do little to nothing to decrease energy consumption while disfavoring measures that result in more efficient consumption, an outcome that they argue undermines FEECA's legislative purpose.

Stakeholders suggest that in place of the RIM Test, the rule should require that utilities analyze cost effectiveness using the Utility Cost Test (UCT), also known as the Program Administrator Test, which is essentially the RIM Test analysis without the lost revenue cost component. Stakeholders argue that this is an improvement on current Commission practice because the UCT compares a utility's cost of saving energy by administering DSM measures to the utility's cost of providing power through supply resources. Additionally, the UCT symmetrically compares the direct utility costs of operating DSM programs against the direct financial benefits of efficiency which are passed on to all customers. Stakeholders suggest that in order to include the UCT in the rule, the Commission could either amend the Cost Effectiveness Manual incorporated into Rule 25-17.008, F.A.C., or alternatively the Commission could provide a standard definition of the UCT test in Rule 25-17.0021, F.A.C.

Staff recommends that the Commission not eliminate or replace the RIM Test. Staff believes that the RIM Test provides valuable information not provided by the UCT or any of the Commission's other cost-effectiveness tests, information staff believes to be relevant to the cost-effectiveness considerations required by FEECA. In particular, as described in more detail below, the RIM Test's consideration of a utility's lost revenue is relevant to FEECA's mandate to consider the costs passed on to the general body of ratepayers.[14]

FEECA declares that it is essential to utilize cost-effective DSM and conservation systems. *See* Section 366.81, F.S. Additionally, FEECA requires that in establishing goals, the Commission must consider the "costs and benefits to the general body of ratepayers as a whole." *See* Section 366.82(3)(b), F.S. Further, FEECA requires that in approving DSM plans and programs for cost recovery, the Commission must examine whether they will result in "an undue impact on the costs passed on to customers." *See* Section 366.82(7), F.S.

For purposes of reporting cost-effectiveness data required by Rule 25-17.0021, F.A.C., the three cost-effectiveness tests used by the Commission are defined and described in Rule 25-17.008, F.A.C., which incorporated the Commission's Cost Effectiveness Manual.[15] The RIM Test is one piece, but an important piece, of the cost-effectiveness puzzle that helps the Commission discern the overall cost-effectiveness picture of potential DSM programs along with the other tests utilized by the Commission.

- The Participants Test analyzes costs and benefits of a DSM measure from the perspective of customers participating in the measure, including the cost of installing DSM equipment and the benefit of reduction in electricity bills.

[14] Section 366.82(3)(b), (7), F.S.
[15] Because only Rule 25-17.0021, F.A.C., was noticed for rule development, the potential amendment of other Commission rules is not the subject of this rulemaking and is not addressed in this recommendation.

- The Total Resource Cost Test measures the net costs and benefits of a DSM program as a resource option compared to other traditional supply resources, including the costs and benefits both to participants and the utility administering the program. Lost revenues (bill reductions) are not considered in the TRC Test because they are treated as a transfer payment—a cost to the utility that exactly matches the benefit to participating customers.

- The Rate Impact Measure Test measures the direction of pressure on rates likely to result from a DSM program relative to the pressure without the DSM program. It compares the change in utility revenue to the change in utility costs to determine whether a DSM measure will place upward or downward pressure on rates for the general body of ratepayers, including customers not participating in the DSM program.

The Cost Effectiveness Manual states that in evaluating conservation programs, "the Commission will review the results of all three tests to determine cost effectiveness." However, Rule 25-17.008(4), F.A.C., states that "[n]othing in this rule shall be construed as prohibiting any party from providing additional data proposing additional formats for reporting cost effectiveness data."

Staff believes that it is important to the Commission's cost-effectiveness analysis under FEECA to consider the estimated impact of lost utility revenue that will result from potential DSM measures. A utility's rates are designed to recover both fixed costs and variable costs from a projected total sales volume. When energy sales (kilowatt-hours or KWH) and thus, total revenue, are reduced through efficiency and conservation, a utility's variable costs decrease but, in general, fixed costs remain unchanged. Thus, all other things remaining equal, a utility would no longer recover all its fixed costs from the lower revenue total. In other words, a loss in energy sales could put upward pressure on rates for the general body of ratepayers because the utility's fixed costs would be spread across fewer KWH. Therefore, an analysis of the estimated impact of a DSM measure on a utility's revenue helps the Commission consider the potential impact on future rates for the general body of ratepayers, as required by FEECA in Section 366.82(3) and (7), F.S.

Although the RIM Test does treat a reduction in the bills of participating customers as "lost revenue," and therefore as a cost both to the utility and to the general body of ratepayers, bill reductions are considered as a benefit under the Participants Test.[16] Staff believes that eliminating the RIM Test and its analysis of lost revenues would restrict the Commission's statutory flexibility to consider a wide array of cost-effectiveness data upon which to determine, in light of variable market conditions, the overall cost effectiveness of a potential DSM measure.

Staff also believes that the spectrum of cost-effectiveness tests required by staff's recommended amendments to the rule will provide the Commission with a broad range of information related to the costs and benefits of available DSM measures—data that will put the Commission in the

[16] It is significant to note that revenue gains resulting from a potential DSM measure are treated in the opposite way: in the Participants Test, it would be an increase in customer bills and therefore a cost, but in the RIM Test they would be a revenue increase and therefore a benefit to the utility. *See* Order No. 24745, *Notice of Adoption of Rule Amendment*, issued on July 7, 1991, in Docket No. 891324-EU, *In Re: Amendment of Rule 25-17.008, F.A.C., pertaining to Conservation and Self-Wheeling Cost Effectiveness Data Reporting Format*.

best position to comply with FEECA's requirements to consider the costs and benefits of those measures on participants, non-participants, and the general body of ratepayers as a whole, as required by FEECA in Section 366.82(3), F.S. In addition, the tests, the RIM Test in particular, will give the Commission at the goal-setting stage information relevant to its statutory mandate to assess whether potential DSM plans and programs may have an undue impact on rates, as required by FEECA in Section 366.82(7), F.S.

For these reasons, staff recommends that the Stakeholders' suggestions to eliminate the RIM Test from the Commission's cost-effectiveness analysis should not be accepted. Staff recommends that the Commission continue utilizing the RIM Test as provided in the proposed amended rule in order to establish a robust record of evidence related to cost effectiveness upon which the Commission can set conservation goals for electric utilities in accordance with the directives prescribed by FEECA and with the full range of flexibility granted to the Commission by statute.

Free Rider Considerations

Stakeholders ask that the Commission include in the rule an explicit bar on the Commission's use of the two-year payback screen as a method for considering free riders. Stakeholders argue that the payback screen as historically applied by the Commission eliminates many of the most common and cost-effective measures available, including many that would benefit low-income customers. They assert that eliminating the two-year payback screen would roughly double the cost-effective savings potential of DSM goals. Stakeholders further assert that the application of a payback screen lacks evidentiary basis, and they suggest that the rule should require utilities to apply evidence-based methodologies that are consistent with industry standard practices to consider overlapping measures, rebound effects, free riders, and interactions with building codes and appliance efficiency standards. Stakeholders also suggest that free ridership should be addressed in the program design phase and through post-implementation evaluation, measurement, and verification (EM&V) to track and assess free rider concerns.

FEECA requires that in developing the goals, the Commission must take into consideration "the costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions." *See* Section 366.82(3)(b), F.S. Additionally, FEECA requires the Commission to consider the "need for incentives to promote . . . energy efficiency and demand-side renewable energy systems." *See* Section 366.82(3)(c), F.S. Furthermore, FEECA provides in Section 366.82(5), F.S., that the Commission shall consider information related to the pursuit of a "least-cost strategy, including *non-utility programs* targeted at reducing and controlling the per capita use of electricity in the state" as well as the impact of building codes and appliance efficiency standards on "the need for *utility-sponsored* conservation and energy efficiency measures and programs." (emphasis added). In approving plans and programs for cost recovery, the Commission "shall have the flexibility to modify or deny plans or programs that would have an undue impact on rates." *See* Section 366.82(7), F.S. It is from these provisions that the Commission derives its statutory mandate to consider "free riders" in analyzing the cost effectiveness of a potential DSM measure.

In the Commission's DSM goal-setting and plan-approval processes, the term "free rider" describes a utility customer who accepts a utility incentive to participate in a DSM measure even though they would likely engage in that DSM activity without the incentive. DSM activity has the inherent benefit to participating customers of lowering electricity consumption and bills, a benefit that operates as a natural incentive to engage in the activity. Thus, it is reasoned that a rational customer would participate if the benefits outweigh the cost. However, a utility incurs costs to administer a DSM measure, including incentives given to customers to encourage participation in the program. These incentives are then recovered in electric rates collected from the general body of ratepayers, including those not participating in the DSM measure, through the ECCR clause.[17] Thus, the Commission has historically sought to limit incentives paid for DSM participation to customers who would likely engage in the conservation activity without the incentive.

The Commission has historically used a time-based "payback screen" to screen out potential free riders.[18] A payback period is the time it takes for a customer to recover through bill reductions the up-front costs of installing a DSM system or adopting a DSM activity. It is reasoned that if a DSM measure would "pay for itself" within a certain period of time, the customer already has enough economic incentive to adopt that system or activity, and an incentive paid to those customers are more likely to be ineffective or superfluous. Thus, those DSM measures are "screened out" in order to avoid collecting through general rates or the ECCR clause incentives paid to customers who were already sufficiently incentivized to participate. In other words, because the incentive paid to a free rider adds no marginal participation in the DSM measure and no marginal contribution to FEECA's objectives, non-participants should not be required to pay for these incentives through increased rates.

It is important to note that there are many market factors that can change the costs and benefits to customers and affect the length of a payback period and whether a utility incentive is necessary. For instance, if there are rebates or tax incentives available for adopting a particular DSM measure, the up-front cost to the customer is reduced, and the payback period is also reduced because it will take less time for the DSM measure to pay for itself through reduced customer bills. Similarly, if fuel costs are high, the customer will realize greater bill reductions, and the DSM measure will take less time to pay for itself. Conversely, low fuel costs and an absence of rebates or tax incentives would result in a longer payback period, and where a DSM measure has a longer payback period, more customers are likely to require the encouragement of utility incentives in order to participate. Thus, staff believes it is important that the Commission maintain a flexible and responsive approach to considering free ridership under whatever market conditions exist at the time of future goal-setting proceedings.

Further, when a DSM measure is "screened out" by a time-based payback screen, that in no way indicates that the DSM measure will be entirely abandoned or that Florida's electricity customers

[17] Rule 25-17.015, F.A.C. governs the Commission's ECCR proceedings.

[18] The use of a time-based payback screen has been recognized and approved by the Commission as far back as its 1994 goal-setting proceeding and used consistently since then. *See e.g.,* Order No. PSC-94-1313-FOF-EG, *Order Setting Conservation Goals*, issued on October 25, 1994, in Docket Nos. 930548-EG, 930549-EG, 930550-EG, and 930551-EG, *In Re: Adoption of Numeric Conservation Goals and Consideration of National Energy Policy Act Standards (Section 111).*; Order No. PSC-09-0855-FOF-EG, *Final Order Approving Numeric Conservation Goals*, issued on December 30, 2009, in Docket Nos. 080407-EG, 080408-EG, 080409-EG, 080410, EG, 080411-EG, and 080412-EG, *In re: Commission review of numeric conservation goals.*

will be deprived of any conservation or efficiency benefits the DSM measure could have produced. In fact, the measures are screened out of a utility's DSM plan precisely because customers are likely to participate in the DSM measure without utility incentives. To that end, the payback screen analysis provides insight as to what types of measures the Commission could include in utility educational programs, such as audits. By redirecting some utility DSM spending from incentives and program administration to educational efforts that inform customers about these quick pay-back efficiency options, the Commission can leverage the inherent benefits of DSM activity to incentivize customers to adopt the "screened out" measure, thereby advancing the goals of FEECA while reducing the overall cost to be passed on to the general body of ratepayers. Thus, FEECA's priorities can still be advanced, and the general body of ratepayers can still experience the associated benefits despite a measure being "screened out" of a utility's DSM portfolio.

Stakeholders ask the Commission to amend the rule to expressly eliminate the use of a time-based payback screen in favor of post-implementation EM&V practices performed by utilities, a costly method that does not prevent free rider participation on the front end and thus increases costs passed on to non-participants through the ECCR clause. Contrary to Stakeholders' assertion that the application of a payback screen lacks evidentiary basis, the Commission has repeatedly considered testimony supporting the application of a payback screen as a method of considering free ridership and addressing the appropriate length of the payback period.[19] Importantly, the Commission has also over-ruled the results of the payback screen and, in order to capture more potential savings through available DSM programs, included in utilities' residential goals DSM measures that were initially screened out by a two-year payback screen.[20]

Staff recommends that the Commission not amend the rule in a way that forecloses its ability to use a time-based payback screen and that the Commission not limit its statutory discretion and flexibility to account for and respond to variable market factors that impact the naturally-occurring incentives of DSM activity. While the application of a time-based payback screen has never been prescribed by Commission rule, and is not prescribed by the recommended rule language, the methodology continues to offer the Commission a valuable tool for considering free ridership and, when the Commission finds its application supported by evidence, for avoiding undue impact on the costs passed on to non-participating customers, as required by FEECA in Sections 366.82(3), (5), and (7), F.S.

Stakeholders also suggest that the Commission exempt from standard free ridership considerations DSM programs and measures designed for low-income customers in order to expand access to utility-sponsored DSM programs.

For the reasons stated above with respect to cost-effectiveness analysis, staff does not recommend that the Commission exempt low-income programs from free rider considerations. Further, staff believes that free ridership in a DSM measure directly affects the utility incentive

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[19] *See, e.g.,* Order No. PSC-09-0855-FOF-EG, at pp. 8-9 (discussing the direct testimony of FPL witness Dean related to the rationale for a two-year payback screen).

[20] *Id.* at 9-10. *See also* Order No. PSC-15-0323-PAA-EG, (stating that the use of a two-year payback screen at the goal-setting stage is "not so rigid as to prevent low-cost measures from being included in carefully crafted utility [DSM] programs").

costs passed on to the general body of ratepayers, and thus that exempting any measures from standard free ridership considerations would violate FEECA's directives under Sections 366.82(3)(b)-(c), F.S.

Subsection (4) Recommended Amendments

In subsection (4), the recommended amended rule addresses the filing requirements for each electric utility to submit a plan to meet its Commission-approved DSM goals. The recommended amendments add specificity to what information must be included in DSM plan filings and update language for consistency. Additionally, paragraph (4)(j) was added to the rule, requiring utilities to file in their DSM plan an estimate of the annual amount to be recovered through ECCR proceedings. The recommended amendment will give the Commission an opportunity at the plan-approval phase to consider the potential costs to be passed on to customers and avoid potentially "undue impact" in accordance with FEECA Section 366.82(7), F.S.

Additional recommended amendments to subsection (4) update the language for consistency and delete redundant or unnecessary language.

Summary of Comments Received & Staff Response

Stakeholders ask the Commission to require utilities to consider in the DSM plan design process strategies for minimizing free ridership, in connection with the post-implementation EM&V measures discussed above in comments on subsection (3). Additionally, Stakeholders suggest that the rule should require utilities to consider "customer segments" in their DSM plan filings rather than "customer classes" in order to include low-income customers separately and distinctly from residential, commercial, and industrial classes.

For the reasons stated above, staff believes a consideration of free ridership is appropriate at the goal-setting stage in connection with the Commission's analysis of the cost effectiveness of potential DSM measures as required by FEECA in Section 366.82(3), F.S. Further, an estimate of the cost effectiveness of each proposed program is required in paragraph (4)(i) of the recommended amendments to the rule, contemplating a continuing need to account for free riders as well as the other cost-effectiveness considerations required by subsection (3). Thus, staff does not recommend that the Commission include additional requirements to consider free rider concerns in subsection (4).

Additionally, staff believes it is unnecessary and counterproductive to consider low-income participants as a separate and distinct customer class for DSM plan-approval purposes. As stated above, FEECA contemplates flexibility in the design of particular measures that can be included within plans and programs that are designed to meet approved conservation goals. Thus, considering programs for low-income customers separately would limit the Commission's statutory ability to approve residential DSM programs that include less cost-effective low-income DSM measures in a portfolio with more cost-effective measures.

Subsection (5) Recommended Amendments

Staff's recommended amendments to subsection (5) are to retain the provision that the Commission has the discretion to review and modify an electric utility's DSM goals, language that was originally contained in subsection (2). No comments were received on subsection (5).

Subsection (6) Recommended Amendments

Subsection (6) of the recommended amended rule relates to the annual DSM reporting required for each electric utility. This subsection was renumbered due to the addition of subsection (5). It contains no substantive amendments, making only minor updates to language for clarity and consistency. No comments were received on subsection (6).

Minor Violation Rules Certification

Pursuant to Section 120.695, F.S., for each rule filed for adoption, the agency head shall certify whether any part of the rule is designated as a rule the violation of which would be a minor violation. Rule 25-17.0021, F.A.C., is on the Commission's minor violation rule list because violation of the rule would not result in economic or physical harm to a person; adverse effects on the public health, safety, or welfare; and would not create a significant threat of such harm. The proposed amendments to the rule would not alter the likelihood or risk of such harms in the event of a violation. Thus, if the Commission proposes the amendment, staff recommends that the Commission certify that Rule 25-17.0021, F.A.C., is a rule the violation of which would be a minor violation pursuant to Section 120.695, F.S.

Statement of Estimated Regulatory Costs

Pursuant to Section 120.54, F.S., agencies are encouraged to prepare a statement of estimated regulatory costs (SERC) before the adoption, amendment, or repeal of any rule. Agencies are required to prepare a SERC for any rule that will have an adverse impact on small business or that is likely to directly or indirectly increase regulatory costs in excess of $200,000 in the aggregate within one year after implementation. The SERC analysis includes whether the rule will, within five years of implementation, have an adverse impact in excess of $1 million in the aggregate on economic factors such as economic growth, private sector job creation or employment, private sector investments, or business competitiveness, productivity, or innovation. If expected adverse impacts or regulatory costs exceed any of the above criteria, a proposed rule may not take effect until it is ratified by the Legislature.

A SERC was prepared and is appended as Attachment B. The SERC concludes that the rule will not have an adverse impact on small business and that the rule is not likely to directly or indirectly increase regulatory costs in excess of $200,000 in the aggregate within one year after implementation. Further, the SERC concludes that the rule will not likely have an adverse impact on economic growth, private sector job creation or employment, private sector investment, or business competitiveness, productivity, or innovation in excess of $1 million in the aggregate within five years of implementation. None of the adverse impact or regulatory cost criteria set forth in Section 120.541(2)(a), F.S., will be exceeded as a result of the recommended amendments to the rule. Thus, the rule does not require legislative ratification pursuant to Section 120.541(3), F.S. In addition, the SERC states that the rule will have no impact on small cities or counties and will not increase the cost to the Commission to implement and enforce the rule. No regulatory alternatives have been submitted pursuant to Section 120.541(1)(a), F.S.

Conclusion

Based on the foregoing, staff recommends the Commission propose the amendment of Rule 25-17.0021, F.A.C., as set forth in Attachment A. In addition, staff recommends that the

Commission certify that Rule 25-17.0021, F.A.C., is a rule the violation of which would be a minor rule violation pursuant to Section 120.695, F.S.

Issue 2: Should this docket be closed?

Recommendation: Yes, if no requests for hearing or JAPC comments are filed, and no proposal for a lower cost regulatory alternative is submitted, the rule should be filed for adoption with the Department of State, and the docket should be closed. (Rubottom)

Staff Analysis: If no requests for hearing or JAPC comments are filed, and no proposal for a lower cost regulatory alternative is submitted pursuant to Section 120.541(1)(a), F.S., the rule may be filed with the Department of State for adoption, and the docket should be closed.

25-17.0021 Goals for Electric Utilities.

(1) The Commission will ~~shall~~ initiate a proceeding at least once every five years to establish ~~numerical~~ goals for each affected electric utility, as defined by Section 366.82(1)(a), F.S.~~, to reduce the growth rates of weather-sensitive peak demand, to reduce and control the growth rates of electric consumption, and to increase the conservation of expensive resources, such as petroleum fuels.~~ The Commission will set annual ~~Overall~~ Residential kilowatt (KW) and kilowatt-hour (KWH) goals and annual ~~overall~~ Commercial/Industrial KW and KWH goals ~~shall be set by the Commission for each year~~ over a ten-year period. The goals will ~~shall~~ be based on:

(a) An assessment of the technical potential of available measures; and

(b) A~~a~~n estimate of the total cost-effective KW ~~kilowatt~~ and KWH ~~kilowatt-hour~~ savings reasonably achievable through demand-side management programs in each utility's service area over a ten-year period.

(2) Pursuant to the schedule in an order establishing procedure in the proceeding to establish demand-side management goals, each utility must file a technical potential study. ~~The Commission shall set goals for each utility at least once every five years.~~ The technical potential study must be used to develop the proposed demand-side management goals, and it must assess the full technical potential of all available demand-side conservation and efficiency measures, including demand-side renewable energy systems, associated with each of the following market segments and major end-use categories.

Residential Market Segment:

(Existing Homes and New Construction should be separately evaluated) Major End-Use Category

(a) Building Envelope Efficiencies.

(b) Cooling and Heating Efficiencies.

(c) Water Heating Systems.

(d) Lighting Efficiencies.

(e) Appliance Efficiencies.

(f) Peak Load Shaving.

(g) Solar Energy and Renewable Energy Sources.

Commercial/Industrial Market Segment:

(Existing Facilities and New Construction should be separately evaluated) Major End-Use Category

(h) Building Envelope Efficiencies.

(i) Cooling and Heating Efficiencies.

(j) Lighting Efficiencies.

(k) Appliance Efficiencies.

(l) Power Equipment/Motor Efficiency.

(m) Peak Load Shaving.

(n) Water Heating Systems.

(o) Refrigeration/Freezing Equipment.

(p) Solar Energy and Renewable Energy Sources.

(q) High Thermal Efficient Self Service Cogeneration.

Each utility's filing must describe how the technical potential study was used to develop the goals filed pursuant to subsection (3) below, including identification of measures that were analyzed but excluded from consideration. ~~The Commission on its own motion or petition by a substantially affected person or a utility may initiate a proceeding to review and, if appropriate, modify the goals. All modifications of the approved goals, plans and programs shall only be on a prospective basis.~~

(3) Pursuant to the schedule in an order establishing procedure in the proceeding to

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establish demand-side management goals, each utility must file its proposed demand-side management goals. ~~In a proceeding to establish or modify goals, each utility shall propose numerical goals for the ten year period and provide ten year projections, based upon the utility's most recent planning process, of the total, cost-effective, winter and summer peak demand (KW) and annual energy (KWH) savings reasonably achievable in the residential and commercial/industrial classes through demand-side management.~~ Each utility must also file demand-side management goals developed under two scenarios: one scenario that includes potential demand-side management programs that pass the Participant and Rate Impact Measure Tests, and one scenario that includes potential demand-side management programs that pass the Participant and Total Resource Cost Tests, as these terms are used in Rule 25-17.008, F.A.C. Each utility's goal projections ~~projection~~ must be based on the utility's most recent planning process and must ~~shall~~ reflect the annual KW and KWH savings, over a ten-year period, from potential demand-side management programs with consideration of overlapping measures, rebound effects, free riders, interactions with building codes and appliance efficiency standards, and the utility's latest monitoring and evaluation of conservation programs and measures. In addition, for each potential demand-side management program identified in the proposed goals and in each scenario described above, each utility must provide overall estimated annual program costs over a ten-year period. ~~Each utility's projections shall be based upon an assessment of, at a minimum, the following market segments and major end-use categories.~~

~~Residential Market Segment:~~

~~(Existing Homes and New Construction should be separately evaluated) Major End-Use Category~~

~~(a) Building Envelope Efficiencies.~~

~~(b) Cooling and Heating Efficiencies.~~

~~(c) Water Heating Systems.~~

~~(d) Appliance Efficiencies.~~

~~(e) Peakload Shaving.~~

~~(f) Solar Energy and Renewable Energy Sources.~~

~~(g) Renewable/Natural gas substitutes for electricity.~~

~~(h) Other.~~

~~Commercial/Industrial Market Segment:~~

~~(Existing Facilities and New Construction should be separately evaluated) Major End-Use Category~~

~~(i) Building Envelope Efficiencies.~~

~~(j) HVAC Systems.~~

~~(k) Lighting Efficiencies.~~

~~(l) Appliance Efficiencies.~~

~~(m) Power Equipment/Motor Efficiency.~~

~~(n) Peak Load Shaving.~~

~~(o) Water Heating.~~

~~(p) Refrigeration Equipment.~~

~~(q) Freezing Equipment.~~

~~(r) Solar Energy and Renewable Energy Sources.~~

~~(s) Renewable/Natural Gas substitutes for electricity.~~

~~(t) High Thermal Efficient Self Service Cogeneration.~~

~~(u) Other.~~

(4) Within 90 days of a final order establishing or modifying goals, each utility must file its demand-side management plan that includes the programs to meet the approved goals, along with program administrative standards that include a statement of the policies and

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procedures detailing the operation and administration of each program. ~~or such longer period as approved by the Commission, each utility shall submit for Commission approval a demand side management plan designed to meet the utility's approved goals.~~ The following information must ~~shall~~ be filed ~~submitted~~ for each demand-side management program included in the utility's demand-side management plan for a ten-year projected horizon period:

(a) The program name;

(b) The program start date;

~~(c) A statement of the policies and procedures detailing the operation and administration of the program;~~

(c) ~~(d)~~ The total number of customers, or other appropriate unit of measure, in each class of customer (i.e. residential, commercial, industrial, etc.) for each calendar year in the planning horizon;

(d) ~~(e)~~ The total number of eligible customers, or other appropriate unit of measure, in each class of customers (i.e., residential, commercial, industrial, etc.) for each calendar year in the planning horizon;

(e) ~~(f)~~ An estimate of the annual number of customers, or other appropriate unit of measure, in each class of customers projected to participate in the program for each calendar year of the planning horizon, including a description of how the estimate was derived;

(f) ~~(g)~~ The cumulative penetration levels of the program by calendar year calculated as the percentage of projected cumulative participating customers, or appropriate unit of measure, by year to the total customers eligible to participate in the program;

(g) ~~(h)~~ Estimates on an appropriate unit of measure basis of the per customer and program total annual KWH reduction, winter KW reduction, and summer KW reduction, both at the customer meter and the generation level, attributable to the program. A summary of all

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assumptions used in the estimates and a list of measures within the program must ~~will~~ be included;

(h) ~~(i)~~ A methodology for measuring actual KW ~~kilowatt~~ and KWH ~~kilowatt-hour~~ savings achieved from each program, including a description of research design, instrumentation, use of control groups, and other details sufficient to ensure that results are valid;

(i) ~~(j)~~ An estimate of the cost-effectiveness of the program using the cost-effectiveness tests required pursuant to Rule 25-17.008, F.A.C. ~~If the Commission finds that a utility's conservation plan has not met or will not meet its goals, the Commission may require the utility to modify its proposed programs or adopt additional programs and submit its plans for approval.~~

(j) An estimate of the annual amount to be recovered through the energy conservation cost recovery clause for each calendar year in the planning horizon.

(5) The Commission may, on its own motion or on a petition by a substantially affected person or a utility, initiate a proceeding to review and, if appropriate, modify the goals. All modifications of the approved goals, plans, and programs will be on a prospective basis.

(6) ~~(5)~~ Each utility must ~~shall~~ submit an annual report no later than March 1 ~~of each year~~ summarizing its demand-side management plan and the total actual achieved results for its approved demand-side management plan in the preceding calendar year. The report must ~~shall~~ contain~~, at a minimum,~~ a comparison of the achieved KW and KWH reductions with the established Residential and Commercial/Industrial goals, and the following information for each approved program:

(a) The name of the utility;

(b) The name of the program and program start date;

(c) The calendar year the report covers;

(d) The t~~T~~otal number of customers, or other appropriate unit of measure, by customer class for each calendar year of the planning horizon;

(e) The t~~T~~otal number of customers, or other appropriate unit of measure, eligible to participate in the program for each calendar year of the planning horizon;

(f) The t~~T~~otal number of customers, or other appropriate unit of measure, projected to participate in the program for each calendar year of the planning horizon;

(g) The potential cumulative penetration level of the program to date calculated as the percentage of projected participating customers to date to the total eligible customers in the class;

(h) The actual number of program participants and the current cumulative number of program participants;

(i) The actual cumulative penetration level of the program calculated as the percentage of actual cumulative participating customers to the number of eligible customers in the class;

(j) A comparison of the actual cumulative penetration level of the program to the potential cumulative penetration level of the program;

(k) A justification for any variance ~~variances~~ greater ~~larger~~ than 15% from ~~for~~ the annual goals established by the Commission;

(l) Using on-going measurement and evaluation results the annual KWH reduction, the winter KW reduction, and the summer KW reduction, both at the meter and the generation level, per installation and program total, based on the utility's approved measurement/evaluation plan;

(m) The per installation cost and the total program cost of the utility;

(n) The net benefits for measures installed during the reporting period, annualized over the life of the program, as calculated by the following formula:

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annual benefits = $B_{npv} \times d/[1 - (1+d)^{-n}]$

where

B_{npv} = cumulative present value of the net benefits over the life of the program for measures installed during the reporting period.

d = discount rate (utility's after tax cost of capital).

n = life of the program.

Rulemaking Authority 350.127(2), 366.05(1)~~, 366.82(1)-(4)~~ FS. Law Implemented 366.82~~(1)-(4)~~ FS. History–New 4-30-93, Amended __________.

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 14, 2023

TO: Jon Rubottom, Attorney

FROM: Sevini K. Guffey, Public Utility Analyst III, Division of Economics SKG

RE: Statement of Estimated Regulatory Costs (SERC) for Proposed Amendment of Rule 25-17.0021, Florida Administrative Code (F.A.C.), Goals for Electric Utilities

Current Rule 25-17.0021, Florida Administrative Code (F.A.C.), Goals for Electric Utilities, establishes the procedures by which the Commission establishes energy conservation goals for each affected electric utility and to review and approve cost effective utility conservation or demand-side management (DSM) programs. The recommended draft revisions to Rule 25-17.0021, F.A.C., are generally to add clarity and specificity to the rule language concerning DSM goals, plans, and programs for electric utilities and to update the rule to improve administrative efficiency.

On December 22, 2022, staff issued a SERC data request to the utilities subject to the Florida Energy Efficiency and Conservation Act, to assess if the utilities would face any incremental economic impacts as a result of the recommended draft revisions to Rule 25-17.0021, F.A.C. On January 13, 2023, the utilities provided responses to staff's SERC data request. In their responses, the utilities stated that the recommended draft rule revisions will not result in significant material differences to the utilities in comparison to the existing rule. As indicated in the SERC, the utilities expect costs that are similar to the amounts expended during the 2019 DSM goals proceeding and do not project any incremental costs at this time. Therefore, the recommended draft rule revisions are not likely to result in incremental regulatory costs, including transactional costs in excess of $1 million in the aggregate within 5 years of implementing the rule.

No regulatory alternatives have been submitted pursuant to Section 120.541(2)(g), Florida Statutes (F.S.). The SERC indicates that none of the adverse impact or cost criteria established in Sections 120.541(2)(a), (c), (d), and (e), F.S., will be exceeded as a result of the recommended draft revisions.

cc: SERC File

FLORIDA PUBLIC SERVICE COMMISSION
STATEMENT OF ESTIMATED REGULATORY COSTS
Rule 25-17.0021, F.A.C., Goals for Electric Utilities

1. Will the proposed rule have an adverse impact on small business? [120.541(1)(b), F.S.] (See Section E., below, for definition of small business.)

   Yes ☐ No ☒

If the answer to Question 1 is "yes", see comments in Section E.

2. Is the proposed rule likely to directly or indirectly increase regulatory costs in excess of $200,000 in the aggregate in this state within 1 year after implementation of the rule? [120.541(1)(b), F.S.]

   Yes ☐ No ☒

If the answer to either question above is "yes", a Statement of Estimated Regulatory Costs (SERC) must be prepared. The SERC shall include an economic analysis showing:

A. Whether the rule directly or indirectly:

(1) Is likely to have an adverse impact on any of the following in excess of $1 million in the aggregate within 5 years after implementation of the rule? [120.541(2)(a)1, F.S.]

Economic growth	Yes ☐	No ☒
Private-sector job creation or employment	Yes ☐	No ☒
Private-sector investment	Yes ☐	No ☒

(2) Is likely to have an adverse impact on any of the following in excess of $1 million in the aggregate within 5 years after implementation of the rule? [120.541(2)(a)2, F.S.]

Business competitiveness (including the ability of persons doing business in the state to compete with persons doing business in other states or domestic markets)	Yes ☐	No ☒
Productivity	Yes ☐	No ☒
Innovation	Yes ☐	No ☒

1

(3) Is likely to increase regulatory costs, including any transactional costs, in excess of $1 million in the aggregate within 5 years after the implementation of the rule? [120.541(2)(a)3, F.S.]

Yes ☐ No ☒

Economic Analysis: Florida Power & Light (FPL), Duke Energy Florida, LLC (DEF), Tampa Electric Company (TECO), Florida Public Utilities Company (FPUC), Orlando Utilities Commission (OUC), and JEA in their responses to staff's SERC data request stated that implementing draft revised Rule 25-17.0021, F.A.C., is not materially different from implementing the current rule and, therefore at this time, the utilities expect to incur costs similar to the costs incurred during the 2019 DSM goal proceedings. The 2019 DSM goal proceeding costs are discussed below as they provide a general view of costs to be expected by the utilities for the next DSM goals proceeding.

Technical Potential Study
The utilities' responses regarding the technical potential study can be found in staff's first data request No. 1.

DEF stated it currently expends approximately $150,000 to prepare and file a technical potential study and does not anticipate any additional costs at this time.

FPUC stated that in 2019 the company incurred approximately $121,821 to prepare and file a technical potential study and expects similar costs to implement the proposed draft rule.

FPL, TECO, OUC, and JEA stated that they do not anticipate incremental cost differences to prepare and file a technical potential study between the existing and proposed draft rule.

Five-Year Cost to Prepare an Estimate of ECCR Clause Recovery Amounts
The utilities' responses regarding costs to prepare an estimate of ECCR Clause Recovery amounts can be found in staff's first data request No. 12.

FPL stated that it does not anticipate any incremental costs associated with preparing an estimate of the amount to be recovered through the annual Energy Conservation Cost Recovery (ECCR) clause. FPL stated that its normal five-year cost is anticipated to be less than $25,000 (less than $5,000 annually).

TECO stated that it projects no incremental costs and that the current estimated five-year cost to prepare an estimate of the amount to be recovered through the annual ECCR clause would be less than $10,000 (less than $2,000 annually).

DEF and FPUC stated that they do not anticipate incremental costs to prepare an estimate of the amount to be recovered through the annual ECCR clause

JEA and OUC stated this is not applicable because JEA and OUC do not have a separate energy conservation cost recovery charge and they are not subject to the Commission's ECCR clause proceedings.

2

<u>Regulatory and Transactional Costs</u>
The utilities' responses regarding regulatory and transactional costs can be found in staff's first data request No. 14.

FPL (including former Gulf Power) stated it incurred approximately $150,000 for consulting fees in the 2019 DSM goals proceeding and expects to incur similar costs for consulting services for the 2024 DSM goal proceeding.

TECO stated that its cost to develop DSM goals in the last proceeding was approximately $300,000 (over 30-month period). TECO projects very little, if any, incremental regulatory including transactional costs to implement the draft rule revisions.

DEF stated that it estimates regulatory costs for this DSM goal proceeding to be approximately $150,000, compared to $169,492, in the last DSM Goals Proceeding.

FPUC stated that its costs were $121,821 (without internal hourly labor costs) during the 2019 DSM goal proceeding and it expects similar costs for the next DSM goal proceeding.

OUC stated that it incurred costs of approximately $500,000 related to the 2019 DSM goals proceedings and it expects similar costs for the forthcoming proceeding.

JEA stated that it does not anticipate incremental regulatory costs as a result of the proposed draft revisions.

<u>Conclusion</u>: The responses discussed above indicate that the utilities expect costs that are similar to the amounts expended during the 2019 DSM goals proceeding and do not project potential incremental costs at this time. Therefore, the recommended draft rule revisions are not likely to result in incremental regulatory costs, including any transactional costs in excess of $1 million in the aggregate within 5 years of implementing the rule.

B. A good faith estimate of: [120.541(2)(b), F.S.]

(1) The number of individuals and entities likely to be required to comply with the rule.

Four investor-owned utilities (FPL, DEF, TECO, and FPUC) and two municipal utilities (OUC and JEA) that are subject to the Florida Energy Efficiency and Conservation Act (FEECA) are required to comply with this rule. However, OUC and JEA, as municipal utilities, are exempt from the ECCR clause requirements of Section 25-17.0021(4)(j), F.A.C., because the Commission does not set rates for municipal utilities.

(2) A general description of the types of individuals likely to be affected by the rule.

Customers in the residential and commercial/industrial market segments of the above described utilities are likely to be affected by this rule.

C. A good faith estimate of: [120.541(2)(c), F.S.]

(1) The cost to the Commission to implement and enforce the rule.

☒ None. To be done with the current workload and existing staff.

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

(2) The cost to any other state and local government entity to implement and enforce the rule.

☒ None. The rule will only affect the Commission.

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

(3) Any anticipated effect on state or local revenues.

☒ None.

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

D. A good faith estimate of the transactional costs likely to be incurred by individuals and entities (including local government entities) required to comply with the requirements of the rule. "Transactional costs" include filing fees, the cost of obtaining a license, the cost of equipment required to be installed or used, procedures required to be employed in complying with the rule, additional operating costs incurred, the cost of monitoring or reporting, and any other costs necessary to comply with the rule. [120.541(2)(d), F.S.]

☐ None. The rule will only affect the Commission.

☒ Minimal. Provide a brief explanation. Please see page 2 for estimated incremental transactional costs.

☐ Other. Provide an explanation for estimate and methodology used.

E. An analysis of the impact on small businesses, and small counties and small cities: [120.541(2)(e), F.S.]

(1) "Small business" is defined by Section 288.703, F.S., as an independently owned and operated business concern that employs 200 or fewer permanent full-time employees and that, together with its affiliates, has a net worth of not more than $5 million or any firm based in this state which has a Small Business Administration 8(a) certification. As to sole proprietorships, the $5 million net worth requirement shall include both personal and business investments.

☒ No adverse impact on small business.

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

(2) A "Small City" is defined by Section 120.52, F.S., as any municipality that has an unincarcerated population of 10,000 or less according to the most recent decennial census. A "small county" is defined by Section 120.52, F.S., as any county that has an unincarcerated population of 75,000 or less according to the most recent decennial census.

☒ No impact on small cities or small counties.

☐ Minimal. Provide a brief explanation.

☐ Other. Provide an explanation for estimate and methodology used.

F. Any additional information that the Commission determines may be useful. [120.541(2)(f), F.S.]

☒ None.

Additional Information:

G. A description of any regulatory alternatives submitted and a statement adopting the alternative or a statement of the reasons for rejecting the alternative in favor of the proposed rule. [120.541(2)(g), F.S.]

☒ No regulatory alternatives were submitted.

☐ A regulatory alternative was received from

☐ Adopted in its entirety.

☐ Rejected. Describe what alternative was rejected and provide a statement of the reason for rejecting that alternative.

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The 2022 Florida Statutes (including Special Session A)

Title XXVII RAILROADS AND OTHER REGULATED UTILITIES | Chapter 366 PUBLIC UTILITIES | View Entire Chapter

366.82 Definition; goals; plans; programs; annual reports; energy audits.—

(1) For the purposes of ss. 366.80-366.83 and 403.519:

(a) "Utility" means any person or entity of whatever form which provides electricity or natural gas at retail to the public, specifically including municipalities or instrumentalities thereof and cooperatives organized under the Rural Electric Cooperative Law and specifically excluding any municipality or instrumentality thereof, any cooperative organized under the Rural Electric Cooperative Law, or any other person or entity providing natural gas at retail to the public whose annual sales volume is less than 100 million therms or any municipality or instrumentality thereof and any cooperative organized under the Rural Electric Cooperative Law providing electricity at retail to the public whose annual sales as of July 1, 1993, to end-use customers is less than 2,000 gigawatt hours.

(b) "Demand-side renewable energy" means a system located on a customer's premises generating thermal or electric energy using Florida renewable energy resources and primarily intended to offset all or part of the customer's electricity requirements provided such system does not exceed 2 megawatts.

(2) The commission shall adopt appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems, specifically including goals designed to increase the conservation of expensive resources, such as petroleum fuels, to reduce and control the growth rates of electric consumption, to reduce the growth rates of weather-sensitive peak demand, and to encourage development of demand-side renewable energy resources. The commission may allow efficiency investments across generation, transmission, and distribution as well as efficiencies within the user base. Moneys received by a utility to implement measures to encourage the development of demand-side renewable energy systems shall be used solely for such purposes and related administrative costs.

(3) In developing the goals, the commission shall evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures, including demand-side renewable energy systems. In establishing the goals, the commission shall take into consideration:

(a) The costs and benefits to customers participating in the measure.

(b) The costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions.

(c) The need for incentives to promote both customer-owned and utility-owned energy efficiency and demand-side renewable energy systems.

(d) The costs imposed by state and federal regulations on the emission of greenhouse gases.

(4) Subject to specific appropriation, the commission may expend up to $250,000 from the Florida Public Service Regulatory Trust Fund to obtain needed technical consulting assistance.

(5) The Department of Agriculture and Consumer Services shall be a party in the proceedings to adopt goals and shall file with the commission comments on the proposed goals, including, but not limited to:

(a) An evaluation of utility load forecasts, including an assessment of alternative supply-side and demand-side resource options.

(b) An analysis of various policy options that can be implemented to achieve a least-cost strategy, including nonutility programs targeted at reducing and controlling the per capita use of electricity in the state.

(c) An analysis of the impact of state and local building codes and appliance efficiency standards on the need for utility-sponsored conservation and energy efficiency measures and programs.

(6) The commission may change the goals for reasonable cause. The time period to review the goals, however, shall not exceed 5 years. After the programs and plans to meet those goals are completed, the commission shall determine what further goals, programs, or plans are warranted and adopt them.

(7) Following adoption of goals pursuant to subsections (2) and (3), the commission shall require each utility to develop plans and programs to meet the overall goals within its service area. The commission may require modifications or additions to a utility's plans and programs at any time it is in the public interest consistent with this act. In approving plans and programs for cost recovery, the commission shall have the flexibility to modify or deny plans or programs that would have an undue impact on the costs passed on to customers. If any plan or program includes loans, collection of loans, or similar banking functions by a utility and the plan is approved by the commission, the utility shall perform such functions, notwithstanding any other provision of the law. However, no utility shall be required to loan its funds for the purpose of purchasing or otherwise acquiring conservation measures or devices, but nothing herein shall prohibit or impair the administration or implementation of a utility plan as submitted by a utility and approved by the commission under this subsection. If the commission disapproves a plan, it shall specify the reasons for disapproval, and the utility whose plan is disapproved shall resubmit its modified plan within 30 days. Prior approval by the commission shall be required to modify or discontinue a plan, or part thereof, which has been approved. If any utility has not implemented its programs and is not substantially in compliance with the provisions of its approved plan at any time, the commission shall adopt programs required for that utility to achieve the overall goals. Utility programs may include variations in rate design, load control, cogeneration, residential energy conservation subsidy, or any other measure within the jurisdiction of the commission which the commission finds likely to be effective; this provision shall not be construed to preclude these measures in any plan or program.

(8) The commission may authorize financial rewards for those utilities over which it has ratesetting authority that exceed their goals and may authorize financial penalties for those utilities that fail to meet their goals, including, but not limited to, the sharing of generation, transmission, and distribution cost savings associated with conservation, energy efficiency, and demand-side renewable energy systems additions.

(9) The commission is authorized to allow an investor-owned electric utility an additional return on equity of up to 50 basis points for exceeding 20 percent of their annual load-growth through energy efficiency and conservation measures. The additional return on equity shall be established by the commission through a limited proceeding.

(10) The commission shall require periodic reports from each utility and shall provide the Legislature and the Governor with an annual report by March 1 of the goals it has adopted and its progress toward meeting those goals. The commission shall also consider the performance of each utility pursuant to ss. 366.80-366.83 and 403.519 when establishing rates for those utilities over which the commission has ratesetting authority.

(11) The commission shall require each utility to offer, or to contract to offer, energy audits to its residential customers. This requirement need not be uniform, but may be based on such factors as level of usage, geographic location, or any other reasonable criterion, so long as all eligible customers are notified. The commission may extend this requirement to some or all commercial customers. The commission shall set the charge for audits by rule, not to exceed the actual cost, and may describe by rule the general form and content of an audit. In the event one utility contracts with another utility to perform audits for it, the utility for which the audits are performed shall pay the contracting utility the reasonable cost of performing the audits. Each utility over which the commission has ratesetting authority shall estimate its costs and revenues for audits, conservation programs, and implementation of its plan for the immediately following 6-month period. Reasonable and prudent unreimbursed costs projected to be incurred, or any portion of such costs, may be added to the rates which would otherwise be charged by a utility upon approval by the commission, provided that the commission shall not allow the recovery of the cost of any company image-enhancing advertising or of any advertising not directly related to an approved conservation program. Following each 6-month period, each utility shall report the actual results for that period to the commission, and the difference, if any, between actual and projected results shall be taken into

account in succeeding periods. The state plan as submitted for consideration under the National Energy Conservation Policy Act shall not be in conflict with any state law or regulation.

(12) Notwithstanding the provisions of s. 377.703, the commission shall be the responsible state agency for performing, coordinating, implementing, or administering the functions of the state plan submitted for consideration under the National Energy Conservation Policy Act and any acts amendatory thereof or supplemental thereto and for performing, coordinating, implementing, or administering the functions of any future federal program delegated to the state which relates to consumption, utilization, or conservation of electricity or natural gas; and the commission shall have exclusive responsibility for preparing all reports, information, analyses, recommendations, and materials related to consumption, utilization, or conservation of electrical energy which are required or authorized by s. 377.703.

(13) The commission shall establish all minimum requirements for energy auditors used by each utility. The commission is authorized to contract with any public agency or other person to provide any training, testing, evaluation, or other step necessary to fulfill the provisions of this subsection.

History.—s. 5, ch. 80-65; s. 2, ch. 81-131; s. 2, ch. 81-318; ss. 5, 15, ch. 82-25; ss. 15, 20, 22, ch. 89-292; s. 4, ch. 91-429; s. 81, ch. 96-321; s. 39, ch. 2008-227; s. 503, ch. 2011-142; s. 70, ch. 2014-17; s. 6, ch. 2015-129.

Item 3

FILED 2/23/2023
DOCUMENT NO. 01240-2023
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 23, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (Andrews, D. Buys, Norris) ALM
Division of Economics (Draper, Hampson) JGH
Office of the General Counsel (Stiller, Dose) JSC

RE: Docket No. 20230017-EI – Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricanes Ian and Nicole, by Florida Power & Light Company.

AGENDA: 03/07/23 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: 03/24/23 (60-Day Interim Deadline)

SPECIAL INSTRUCTIONS:

Case Background

On January 23, 2023, Florida Power & Light Company (FPL or Company) filed a petition for a limited proceeding seeking authority to implement an interim storm restoration recovery charge to recover $1.3 billion for the incremental restoration costs related to Hurricanes Ian and Nicole and to replenish the storm reserve. This amount includes $18.8 million in interest.

FPL has also presented an alternate storm charge calculation in its petition, which combines the recovery of incremental storm costs associated with Hurricanes Ian and Nicole with the remaining amounts to be collected for Hurricanes Michael, Sally, and Zeta, which have been previously approved by the Commission for Gulf Power Company (GPC).[1] This alternate

[1]Order No. PSC-2019-0221-PCO-EI, issued June 3, 2019, in Docket No. 20190038-EI, *In re: Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricane Michael, by Gulf Power*

calculation estimates a total of $1.5 billion for incremental restoration costs related to Hurricanes Michael, Sally, Zeta, Ian, and Nicole and to replenish the storm reserve. This amount includes $21.6 million in interest.

FPL filed its petition pursuant to the provisions of the 2021 Settlement Agreement (2021 Settlement) approved by the Commission in Order No. PSC-2021-0446-S-EI.[2] Pursuant to the 2021 Settlement, the Company can recover storm costs on an interim basis beginning 60 days following the filing of a petition for recovery. FPL has proposed interim storm restoration charges applicable to all rate classes over a 12-month recovery period, effective with the first billing cycle of April 2023, subject to a final true-up.

The Commission has jurisdiction over this matter pursuant to Sections 366.04, 366.05, 366.06, and 366.076, Florida Statutes.

Company; and Order No. PSC-2022-0406-FOF-EI, issued November 21, 2022, in Docket No. 20200041-EI, *In re: Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricane Sally, by Gulf Power Company.*

[2]Order No. PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

Discussion of Issues

Issue 1: Should the Commission authorize FPL to implement an interim storm restoration recovery charge?

Recommendation: Yes. The Commission should authorize FPL to implement an interim storm restoration recovery charge, subject to refund. Once the total actual storm costs are known, FPL should be required to file documentation of the storm costs for Commission review and true up of any excess or shortfall. (Andrews)

Staff Analysis: As stated in the Case Background, FPL filed a petition for a limited proceeding seeking authority to implement an interim storm restoration recovery charge to recover an estimated total of $1.3 billion for incremental restoration costs related to Hurricanes Ian and Nicole and to replenish the storm reserve. In its petition, FPL requested to replenish the storm reserve to the pre-storm level of $219.9 million.

The petition was filed pursuant to the provisions of the 2021 Settlement approved by the Commission in Order No. PSC-2021-0446-S-EI. Storm restoration costs for Ian and Nicole were incurred during the term of the 2021 Settlement. Pursuant to Paragraph 10 of the 2021 Settlement, FPL can begin recovery of storm costs 60 days following the filing of a petition for recovery.

FPL also prepared an alternate storm charge calculation seeking authority to implement an interim storm restoration recovery charge to recover an estimated total of $1.5 billion which combines the incremental restoration costs related to Hurricanes Ian and Nicole with the remaining amounts to be collected for Hurricanes Michael, Sally, and Zeta, which have been previously approved by the Commission for GPC, and to replenish the storm reserve.[3]

In its petition, FPL asserted that it incurred total retail recoverable costs of approximately $1.5 billion as a result of Hurricanes Michael, Sally, Zeta, Ian, and Nicole. The Company further asserted that this amount was calculated in accordance with the Incremental Cost and Capitalization Approach methodology prescribed in Rule 25-6.0143, Florida Administrative Code.

The approval of an interim storm restoration recovery charge is preliminary in nature and is subject to refund pending further review once the total actual storm restoration costs are known. After the actual costs are reviewed for prudence and reasonableness, and are compared to the actual amount recovered through the interim storm restoration recovery charge, a determination will be made whether any over/under recovery has occurred. The disposition of any over/under recovery, and associated interest, will be considered by the Commission at a later date.

Based on a review of the information provided by FPL in its petition, staff recommends the Commission authorize the Company to implement an interim storm restoration recovery charge subject to refund. Once the total actual storm costs are known, FPL should be required to file documentation of the storm costs for Commission review and true-up of any excess or shortfall.

[3]Order Nos. PSC-2019-0221-PCO-EI; and PSC-2022-0406-FOF-EI.

Issue 2: What is the appropriate security to guarantee the funds collected subject to refund through the interim storm restoration charge?

Recommendation: The appropriate security to guarantee the funds collected subject to refund is a corporate undertaking. (D. Buys)

Staff Analysis: Staff recommends that all funds collected subject to refund be secured by a corporate undertaking. The criteria for a corporate undertaking include sufficient liquidity, ownership equity, profitability, and interest coverage to guarantee any potential refund. FPL requested a 12-month collection period from April 2023 through March 2024 for Interim Storm Cost Recovery Charges of $1.5 billion related to Hurricanes Michael, Sally, Zeta, Ian and Nicole. Staff reviewed FPL's three most recent annual reports filed with the Commission (2021, 2020, and 2019) to determine if the Company can support a corporate undertaking to guarantee the funds collected for recovery of incremental storm restoration costs related to the weather events. FPL's financial information demonstrates the Company has acceptable levels of liquidity, ownership equity, profitability, and interest coverage to support a potential refund of $1.5 billion. Moreover, it is improbable FPL will be required to refund the entire requested amount.

Staff believes FPL has adequate resources to support a corporate undertaking in the amount requested. Based on this analysis, staff recommends that a corporate undertaking of $1.5 billion is acceptable. This brief financial analysis is only appropriate for deciding if the Company can support a corporate undertaking in the amount proposed and should not be considered a finding regarding staff's position on other issues in this proceeding.

Issue 3: Should the Commission approve FPL's proposed interim storm restoration recovery charge tariff?

Recommendation: No. The Commission should deny FPL's proposed interim storm restoration recovery charge tariff sheet No. 8.030.7. The Commission should approve FPL's alternate storm charge calculation and associated tariff sheet as shown in Attachment A to this recommendation, effective with the first billing cycle of April 2023. Furthermore, effective with the first billing cycle of April 2023, tariff sheet Nos. 8.030.4, 8.030.5, and 8.030.6 should be cancelled, as shown in Attachment A to the recommendation. The alternate storm charge calculation avoids significant disparities in surcharges among customers of one, consolidated utility, reduces regulatory lag and interest payments, and mitigates the potential for overlapping storm recovery charges in the future. The interim storm restoration recovery charge should be subject to a final true-up. (Hampson, Draper, Stiller)

Staff Analysis: FPL is seeking approval of interim storm cost recovery surcharges associated with Hurricanes Ian and Nicole as shown in proposed tariff sheet No. 8.030.7 (Appendix F to the petition). The surcharges would be applicable to all rate classes and customers served by FPL including customers previously served by Gulf Power Company (GPC or FPL's Northwest Florida).

Currently, bills for FPL's Northwest Florida customers include surcharges for Hurricanes Michael, which equates to $8 on the residential 1,000 kilowatt-hour (kWh) bill, and Sally ($3/1,000 kWh). The Hurricane Michael surcharge went into effect in July 2019 and was approved to terminate in October 2023. Once the Hurricane Michael surcharge terminates, the Commission approved that the $3/1,000 kWh residential Hurricane Sally surcharge would increase to $10/1,000 kWh. Once recovery of Hurricane Sally is complete in October 2024, the Commission approved the recovery of Hurricane Zeta ($9.34/1,000 kWh) for the months of November and December 2024. These hurricanes impacted GPC's service territory prior to the merger of FPL and GPC. Tariff sheet Nos. 8.030.4, 8.030.5, and 8.030.6 show the currently approved surcharges for Michael, Sally, and Zeta, applicable to FPL's Northwest Florida customers. FPL indicated in its calculations in Appendix A of the petition that the storm costs associated with the Hurricane Michael surcharge are expected to be fully recovered by March 31, 2023.

For the reasons discussed below, staff is recommending approval of FPL's alternate storm charge calculation and associated tariff sheets which were provided in Appendix H to the petition. The alternate storm charge calculation combines the recovery of incremental storm costs associated with Hurricanes Ian and Nicole with the remaining amounts to be collected for Hurricanes Michael, Sally, and Zeta, which have previously been approved by the Commission. Accordingly, the alternate proposal cancels the current Hurricanes Michael, Sally, and Zeta tariff sheets effective April 2023, that are applicable to FPL's Northwest Florida customers only, and provides instead the proposed "2022 consolidated interim storm restoration recovery" tariff sheet No. 8.030.7 (alternate storm tariff). The alternate storm tariff, which staff recommends the Commission approve, is designed to recover the incremental storm-related costs related to Hurricanes Michael, Sally, Zeta, Ian, and Nicole from all FPL customers.

The current storm surcharges for Sally and Zeta applicable to FPL's Northwest Florida customers were established in 2022 by Final Order of the Commission following a disputed fact hearing.[4] Testimony filed by FPL in 2021 in its rate case indicated that FPL's Northwest Florida legacy[5] storm restoration costs and surcharges associated with Hurricanes Michael and Sally were to remain applicable to only those customers.[6] Final orders of the Commission are generally afforded administrative finality and are not subject to subsequent modification.[7] The issue of maintaining the current surcharge in place for FPL's Northwest Florida customers only until full recovery was not specifically litigated or a material issue in either the prior storm recovery or FPL rate case docket. Staff is not persuaded that finality is attached to this issue. Moreover, administrative finality does not apply where there has been a substantial change in circumstances or a demonstrated public interest.[8] Staff believes both are present in this docket and, accordingly, the Commission has the legal authority to unify the charges.[9]

Hurricanes Ian and Nicole affected only FPL Peninsular customers, i.e., customers served by FPL prior to the merger with GPC. The proposal to apply the surcharge for this storm recovery to all current FPL customers, including FPL's Northwest Florida customers who were not impacted, is a substantial change in circumstances from the prior approach of segregating costs based on impacts. Staff believes that spreading costs evenly across customers for all storms no matter the location of impacts is the appropriate reaction to these changed circumstances.[10]

The alternate storm charge calculations project a 12-month recovery period (April 2023 through March 2024), subject to a final true-up. Under the currently-approved recovery schedule, recovery of Hurricanes Sally and Zeta costs are projected to be complete in December 2024. In response to staff's data request, FPL stated that this accelerated recovery of storm costs would "benefit FPL and its general body of customers by reducing the amount of interest recovered from customers and regulatory lag, while also mitigating the potential for overlapping storm recovery charges in the future."[11] As to whether the alternative is preferable, FPL stated in its response that it "views both as being potentially appropriate options for storm cost recovery."[12]

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[4] Order No. PSC-2022-0406-FOF-EI, issued on November 21, 2022, in Docket Nos. 20200241-EI, 20210178-EI, and 20210179-EI, in *In re: Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricane Sally, In re: Petition for evaluation of Hurricane Isaias and Tropical Storm Eta storm costs, by Florida Power & Light Company,* and *In re: Petition for limited proceeding for recovery of incremental storm restoration costs and associated true-up process related to Hurricane Zeta, by Gulf Power Company.*
[5] FPL and GPC were separate ratemaking entities until the end of 2021.
[6] Document No. 02776-2021 in Docket No. 20210015-EI, Direct Testimony of Tiffany Cohen, p. 30 lns. 9-15.
[7] *Peoples Gas System, Inc. v. Mason*, 187 So. 2d 335, 339 (Fla. 1966) ("orders of administrative agencies must eventually pass out of the agency's control and become final and no longer subject to modification").
[8] *Delray Medical Center, Inc. v Agency for Health Care Admin.*, 5 So. 3d 26, 29 (Fla. 4th DCA 2009).
[9] In response to a data request from staff, FPL concurred that there is no legal prohibition on the Commission imposing a uniform storm surcharge on all current FPL customers. Document No. 01037-2023.
[10] *See Mason*, 187 So. 2d at 339 ("actions of administrative agencies are usually concerned with deciding issues according to a public interest that often changes with shifting circumstances and passage of time").
[11] *Id.*
[12] *Id.*

FPL explained that it has allocated the storm cost recovery amount to the rate classes consistent with the rate design approved in the 2021 Settlement.[13] Staff reviewed the storm cost recovery allocation and calculation of rates, for FPL's proposal and the alternate calculations, and it appears that FPL has calculated rates in accordance with the 2021 Settlement, using the most recent load research study and projected billing determinants for the recovery period. If approved by the Commission, the storm cost recovery surcharge would be included in the non-fuel energy charge on customer bills, which FPL states is consistent with its standard practice.

For residential customers, the staff-recommended alternate surcharge would be 1.530 cents per kWh, which would equate to $15.30 on a 1,000 kWh residential bill. Under FPL's proposed tariff, for residential customers, the surcharge would be 1.384 cents per kWh, which would equate to $13.84 on a 1,000 kWh residential bill. Under FPL's proposal, FPL's Northwest Florida customers would pay the proposed $13.84/1,000 kWh while continuing to pay the approved Hurricanes Sally and Zeta surcharges. Staff notes that FPL's Northwest Florida customers will have paid for all the Hurricane Michael costs by March 31, 2023.

Under the alternate tariff, the FPL Peninsular customers would pay a storm recovery surcharge that is $1.46 ($15.30-$13.84) higher than FPL's proposal on the 1,000 kWh bill for a 12-month period. However, FPL's Northwest Florida customers would save monthly between $11 (Hurricanes Michael and Sally surcharges) to $9.34 (Hurricane Zeta surcharge) on the 1,000 kWh bill for a 21-month period. Staff believes that the savings to FPL Northwest Florida customers, in addition to the reasons discussed above, outweigh the incremental $1.46/1,000 kWh for the FPL Peninsular customers, when comparing the two storm recovery options.

CONCLUSION

The Commission should deny FPL's proposed interim storm restoration recovery charge tariff No. 8.030.7. The Commission should approve FPL's alternate storm charge calculation and associated tariff sheet as shown in Attachment A to this recommendation, effective with the first billing cycle of April 2023. Furthermore, effective with the first billing cycle of April 2023, tariff sheet Nos. 8.030.4, 8.030.5, and 8.030.6 would be cancelled, as shown in Attachment A to the recommendation. The alternate storm charge calculation avoids significant disparities in surcharges among customers of one, consolidated utility, reduces regulatory lag and interest payments, and mitigates the potential for overlapping storm recovery charges in the future. The interim storm restoration recovery charge should be subject to a final true-up.

[13]Order No. PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

Issue 4: Should this docket be closed?

Recommendation: No. This docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted. (Stiller)

Staff Analysis: No, this docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted.

FLORIDA POWER & LIGHT COMPANY Canceled Original Sheet No. 8.030.4

~~(Continued from Sheet No. 8.030.3)~~

~~HURRICANE MICHAEL STORM RESTORATION RECOVERY~~

~~APPLICATION:~~

~~The Storm Restoration Recovery Surcharge is designed to recover incremental storm related costs incurred by the Company related to Hurricane Michael. It is applicable to all accounts within the service area previously served by Gulf Power. The factor is applicable to the Energy Charge under FPL's various rate schedules.~~

~~Rate Schedule~~	~~¢/kWh~~
~~ALL KWH – RS-1, RTR-1~~	~~0.800~~
~~GS-1, GST-1~~	~~0.881~~
~~GSD-1, GSDT-1, GSD-1EV, HLFT-1, SDTR-1~~	~~0.443~~
~~GSLD-1, GSLDT-1, GSLD-1EV, CS-1, CST-1, HLFT-2, SDTR-2~~	~~0.347~~
~~GSLD-2, GSLDT-2, CS-2, CST-2, HLFT-3, SDTR-3~~	~~0.234~~
~~GSLD-3, GSLDT-3, CS-3, CST-3~~	~~0.234~~
~~OS-2~~	~~1.178~~
~~CILC-1(G)~~	~~0.347~~
~~CILC-1(D)~~	~~0.347~~
~~CILC-1(T)~~	~~0.234~~
~~SL-1, SL-1M, PL-1, LT-1~~	~~1.178~~
~~OL-1~~	~~1.178~~
~~OS I/II~~	~~1.178~~
~~SL-2, SL-2M, GSCU-1~~	~~1.178~~
~~SST-1(T), ISST-1(T)~~	~~0.234~~
~~SST-1(D1), SST-1(D2) SST-1(D3), ISST-1(D)~~	~~0.234~~

RESERVED FOR FUTURE USE

~~(Continued on Sheet No. 8.030.5)~~

Issued by: Tiffany Cohen, ~~Senior Director, Regulatory Rates, Cost of Service and Systems~~Executive Director, Rate Development & Strategy
Effective: ~~January 1, 2022~~

~~(Continued from Sheet No. 8.030.4)~~

~~HURRICANE SALLY STORM RESTORATION RECOVERY~~

~~APPLICATION:~~

~~The Storm Restoration Recovery Surcharge is designed to recover incremental storm-related costs incurred by the Company related to Hurricane Sally. It is applicable to all accounts within the service area previously served by Gulf Power. The factor is applicable to the Energy Charge under FPL's various rate schedules.~~

~~Rate Schedule~~	~~¢/kWh~~
~~ALL KWH -- RS-1, RTR-1~~	~~0.300~~
~~GS-1, GST-1~~	~~0.325~~
~~GSD-1, GSDT-1, GSD-1EV, HLFT-1, SDTR-1~~	~~0.168~~
~~GSLD-1, GSLDT-1, GSLD-1EV, CS-1, CST-1, HLFT-2, SDTR-2~~	~~0.131~~
~~GSLD-2, GSLDT-2, CS-2, CST-2, HLFT-3, SDTR-3~~	~~0.087~~
~~GSLD-3, GSLDT-3, CS-3, CST-3~~	~~0.087~~
~~OS-2~~	~~0.228~~
~~CILC-1(G)~~	~~0.131~~
~~CILC-1(D)~~	~~0.131~~
~~CILC-1(T)~~	~~0.087~~
~~SL-1, SL-1M, PL-1, LT-1~~	~~0.228~~
~~OL-1~~	~~0.228~~
~~OS I/II~~	~~0.228~~
~~SL-2, SL-2M, GSCU-1~~	~~0.228~~
~~SST-1(T), ISST-1(T)~~	~~0.087~~
~~SST-1(D1), SST-1(D2) SST-1(D3), ISST-1(D)~~	~~0.087~~

RESERVED FOR FUTURE USE

~~(Continued on Sheet No. 8.031)~~

Issued by: Tiffany Cohen, ~~Senior Director, Regulatory Rates, Cost of Service and Systems~~ Executive Director, Rate Development & Strategy

~~(Continued from Sheet No. 8.030.5)~~

~~HURRICANE ZETA STORM RESTORATION RECOVERY~~

~~APPLICATION:~~

~~The Storm Restoration Recovery Surcharge is designed to recover incremental storm related costs incurred by the Company related to Hurricane Zeta. It is applicable to all accounts within the service area previously served by Gulf Power. The factor is applicable to the Energy Charge under FPL's various rate schedules.~~

~~Rate Schedule~~	~~¢/kWh~~
~~ALL KWH – RS-1, RTR-1~~	~~0.934~~
~~GS-1, GST-1~~	~~0.960~~
~~GSD-1, GSDT-1, GSD-1EV, HLFT-1, SDTR-1~~	~~0.476~~
~~GSLD-1, GSLDT-1, GSLD-1EV, CS-1, CST-1, HLFT-2, SDTR-2~~	~~0.342~~
~~GSLD-2, GSLDT-2, CS-2, CST-2, HLFT-3, SDTR-3~~	~~0.208~~
~~GSLD-3, GSLDT-3, CS-3, CST-3~~	~~0.208~~
~~OS-2~~	~~0.523~~
~~CILC-1(G)~~	~~0.342~~
~~CILC-1(D)~~	~~0.342~~
~~CILC-1(T)~~	~~0.208~~
~~SL-1, SL-1M, PL-1, LT-1~~	~~0.523~~
~~OL-1~~	~~0.523~~
~~OS I/II~~	~~0.523~~
~~SL-2, SL-2M, GSCU-1~~	~~0.523~~
~~SST-1(T), ISST-1(T)~~	~~0.208~~
~~SST-1(D1), SST-1(D2) SST-1(D3), ISST-1(D)~~	~~0.208~~

~~(Continued on Sheet No. 8.031)~~

~~**Issued by: Tiffany Cohen, Senior Director, Regulatory Rates, Cost of Service and Systems**~~
~~**Effective:**~~

(Continued from Sheet No. 8.030.3)

2022 CONSOLIDATED INTERIM STORM RESTORATION RECOVERY

APPLICATION:

The Consolidated Interim Storm Restoration Recovery Surcharge is designed to recover incremental storm-related costs incurred by the Company related to Hurricanes Michael, Sally, Zeta, Ian, and Nicole. The factor is applicable to the Energy Charge under FPL's various rate schedules.

Rate Schedule	¢/kWh
ALL KWH - RS-1, RTR-1	1.530
GS-1, GST-1	1.414
GSD-1, GSD-1EV, GSDT-1, HLFT-1, SDTR-1	0.675
GSLD-1, GSLD-1EV, GSLDT-1, CS-1, CST-1, HLFT-2, SDTR-2	0.661
GSLD-2, GSLDT-2, CS-2, CST-2, HLFT-3, SDTR-3	0.521
GSLD-3, GSLDT-3, CS-3, CST-3	0.039
OL-1	4.624
OS-2	2.409
SL-1, PL-1, LT-1, OS I/II	1.526
SL-1M	0.955
SL-2	0.711
SL-2M	1.808
SST-1(T), ISST-1(T)	0.058
SST-1(D1), SST-1(D2), SST-1(D3), ISST-1(D)	1.892
CILC-1(D)	0.481
CILC-1(G)	0.583
CILC-1(T)	0.028
MET	0.660
GSCU-1	2.591

(Continued on Sheet No. 8.031)

Issued by: Tiffany Cohen, Executive Director, Rate Development & Strategy
Effective:

Item 4

FILED 2/23/2023
DOCUMENT NO. 01241-2023
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 23, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (Gatlin, D. Buys, Hinson, Norris) ALM
Division of Economics (Draper, Hampson) JGH
Office of the General Counsel (Thompson, Sandy) JSC

RE: Docket No. 20230019-EI – Petition for recovery of costs associated with named tropical systems during the 2018-2022 hurricane seasons and replenishment of storm reserve, by Tampa Electric Company.

AGENDA: 03/07/23 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: 03/24/2023 (60-day Interim Deadline)

SPECIAL INSTRUCTIONS:

Case Background

On January 23, 2023, Tampa Electric Company (TECO or Company) filed a petition for a limited proceeding seeking authority to implement an interim storm restoration recovery charge to recover $131 million for the incremental restoration costs related to Tropical Storms Alberto, Nestor, and Eta, and Hurricanes Dorian, Elsa, Ian, and Nicole, as well as the replenishment of its storm reserve. (collectively, "the storms") Included in the $131 million is interest charged for Hurricanes Ian and Nicole. Pursuant to the 2021 Stipulation and Settlement Agreement (2021 Settlement) approved by the Commission in Order No. PSC-2021-0423-S-EI, the recovery of storm costs from customers will begin, on an interim basis, 60 days after the filing of a cost recovery petition and tariff with the Commission.[1] TECO requested a 12-month recovery period, applied to all bills starting with the first billing cycle of April 2023.

The Commission has jurisdiction over this matter pursuant to Sections 366.04, 366.05, 366.06, and 366.076, Florida Statutes.

[1]Order No. PSC-2021-0423-S-EI, issued November 10, 2021, in Docket No. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company.*

Discussion of Issues

Issue 1: Should the Commission authorize TECO to implement an interim storm restoration recovery charge?

Recommendation: Yes. The Commission should authorize TECO to implement an interim storm restoration recovery charge, subject to refund. Once the total actual storm costs are known, TECO should be required to file documentation of the total storm costs for Commission review and true-up of any excess or shortfall. (Hinson)

Staff Analysis: As stated in the Case Background, TECO filed a petition to seek recovery of $131 million in incremental storm restoration costs for the Storms as well as the replenishment of its storm reserve. In its petition, TECO requested to replenish the storm reserve to $55.8 million.

The petition was filed pursuant to the provisions of the 2021 Settlement. Pursuant to paragraph 8(a) of the 2021 Settlement, TECO is authorized to seek recovery of costs associated with any tropical storms named by the National Hurricane Center. Recovery of storm costs will begin, on an interim basis, 60 days following the filing of a petition for recovery.

In its petition, TECO asserted that it incurred approximate recoverable costs in the amounts of $7,499,858 for Hurricane Dorian; $1,874,575 for Hurricane Elsa; $119,216,291 for Hurricane Ian; $1,152,980 for Hurricane Nicole; $1,944 for Tropical Storm Alberto; $8,282 for Tropical Storm Nestor; and $729,515 for Tropical Storm Eta. The remaining $397,518 is for GPS software used to track vendor crews identified by TECO as ARCOS, implemented pursuant to the 2019 Settlement Agreement under the provision of Future Process Improvements.[2] The Company further asserted that all amounts were calculated in accordance with the Incremental Cost and Capitalization Approach methodology prescribed in Rule 25-6.0143, Florida Administrative Code.

The approval of an interim storm restoration recovery charge is preliminary in nature and is subject to refund pending further review once the total actual storm restoration costs are known. After the actual costs are reviewed for prudence and reasonableness, and are compared to the actual amount recovered through the interim storm restoration recovery charge, a determination will be made whether any over/under recovery has occurred. The disposition of any over or under recovery, and associated interest, will be considered by the Commission at a later date.

Based on a review of the information provided by TECO in its petition, staff recommends that the Commission authorize the Company to implement an interim storm restoration recovery charge subject to refund. Once the total actual storm costs are known, TECO should be required to file documentation of the storm costs for Commission review and true-up of any excess or shortfall.

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[2]Order No. PSC-2019-0234-AS-EI, issued June 14, 2019, in Docket No. 20170271-EI, *In re: Petition for recovery of costs associated with named tropical systems during the 2015, 2016, and 2017 hurricane seasons and replenishment of storm reserve subject to final true-up, Tampa Electric Company.*

Issue 2: What is the appropriate security to guarantee the amount collected subject to refund through the interim storm restoration recovery charge?

Recommendation: The appropriate security to guarantee the funds collected subject to refund is a corporate undertaking. (D. Buys)

Staff Analysis: Staff recommends that all funds collected subject to refund be secured by a corporate undertaking. The criteria for a corporate undertaking include sufficient liquidity, ownership equity, profitability, and interest coverage to guarantee any potential refund. TECO requested a 12-month collection period from April 2023 through March 2024 for Interim Storm Cost Recovery Charges of $130,881,964 related to the Storms, including the ARCOS cost. Staff reviewed TECO's three most recent annual reports filed with the Commission (2021, 2020, and 2019) to determine if the Company can support a corporate undertaking to guarantee the funds collected for recovery of incremental storm restoration costs related to all the weather events. TECO's financial information demonstrates the Company has a deficient level of liquidity; that is, current assets are less than current liabilities. However, the Company has sufficient levels of ownership equity, profitability, and interest coverage to support a potential refund of $131 million. TECO's average net income for the three years 2021, 2020, and 2019 is almost three times the requested corporate undertaking amount ($352 million vs. $131 million). Moreover, it is improbable TECO will be required to refund the entire requested amount.

Staff believes TECO has adequate resources to support a corporate undertaking in the amount requested. Based on this analysis, staff recommends that a corporate undertaking of $131 million is acceptable. This brief financial analysis is only appropriate for deciding if the Company can support a corporate undertaking in the amount proposed and should not be considered a finding regarding staff's position on other issues in this proceeding.

Issue 3: Should the Commission approve TECO's proposed interim storm restoration recovery charge tariff as shown in Attachment A to the recommendation?

Recommendation: Yes. The Commission should approve TECO's proposed interim storm restoration recovery charge tariff, as shown in Attachment A to this recommendation, effective with the first billing cycle of April 2023 through March 2024. The Commission should also approve TECO's other tariff revisions, as provided in its petition, which refer to the proposed storm surcharge. The interim storm restoration recovery charge should be subject to a final true-up. (Hampson)

Staff Analysis: TECO is seeking approval of interim storm cost recovery surcharges associated with the Storms. The proposed interim storm cost recovery surcharges are shown in proposed Tariff Sheet No. 6.024 (Attachment A to this recommendation). The surcharges would be applicable to all rate classes. The Company has also proposed changes to several other tariffs to include references to the proposed interim storm cost recovery surcharge, as well as a definition for the storm surcharge in its technical terms and abbreviations section. These tariff modifications are included in Exhibit 6 (clean version) and Exhibit 7 (legislative version) to TECO's petition.

TECO explained that it has allocated the storm cost recovery amount to the rate classes consistent with the rate design approved in the 2021 Settlement.[3] Staff reviewed the storm cost recovery allocation and calculation of rates and it appears that TECO has calculated rates in accordance with the 2021 Settlement, using projected billing determinants for the recovery period.

The interim storm restoration recovery charge calculations are shown in Exhibit 5 to TECO's petition. For residential customers, the surcharge would be 1.022 cents per kilowatt-hour (kWh), which would equate to $10.22 on a 1,000 kWh residential bill. If approved by the Commission, the storm cost recovery surcharge would be included in the non-fuel energy charge on customer bills.

CONCLUSION

Staff recommends that the Commission approve TECO's proposed interim storm restoration recovery charge tariff, as shown in Attachment A to this recommendation, effective with the first billing cycle of April 2023 through March 2024. The Commission should also approve TECO's other tariff revisions which refer to the proposed storm surcharge. Furthermore, the interim storm restoration recovery charge should be subject to a final true-up.

[3]Order No. PSC-2021-0423-S-EI, issued November 10, 2021, in Docket No. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company.*

Issue 4: Should this docket be closed?

Recommendation: No. This docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted. (Thompson, Sandy)

Staff Analysis: No, this docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

ORIGINAL SHEET NO. 6.024

STORM SURCHARGE

Storm Surcharge: The following charges shall be applied to each kilowatt-hour delivered and billed on monthly bills from April 2023 through March 2024. The following factors by rate schedule were calculated using the approved formula and allocation method approved by the Florida Public Service Commission

Rate Schedules	Energy Rate ¢/kWh
RS (all tiers), RSVP-1 (all pricing periods)	1.022
GS, GST (all pricing periods), CS	1.061
GSD, GSDO, SBD, GSDT and SBDT (all pricing periods)	0.238
GSLDPR, GSLDTPR, SBLDPR and SBLDTPR (all pricing periods)	0.127
GSLDSU, GSLDTSU, SBLDSU and SBLDTSU (all pricing periods)	0.028
LS-1, LS-2	0.326

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

Item 5

FILED 2/23/2023
DOCUMENT NO. 01242-2023
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

Capital Circle Office Center ● 2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 23, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (Snyder, D. Buys, Norris) ALM
Division of Economics (Draper, Hampson) JGH
Office of the General Counsel (Brownless, Watrous) JSC

RE: Docket No. 20230020-EI – Petition for limited proceeding for recovery of incremental storm restoration costs related to Hurricanes Elsa, Eta, Isaias, Ian, Nicole, and Tropical Storm Fred, by Duke Energy Florida, LLC.

AGENDA: 03/07/23 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: 03/24/23 (60-Day Interim Deadline)

SPECIAL INSTRUCTIONS:

Case Background

On January 23, 2023, Duke Energy Florida, LLC (DEF or Company) filed a petition for a limited proceeding seeking authority to implement an interim storm restoration recovery charge to recover $442.1 million for the incremental restoration costs related to Hurricanes Elsa, Eta, Ian, Isaias, and Nicole and Tropical Storm Fred, as well as to replenish its storm reserve. This amount includes approximately $4.5 million in interest.

DEF filed its petition pursuant to the provisions of the 2017 Second Revised and Restated Settlement Agreement (2017 Settlement) approved by the Commission in Order No. PSC-2017-0451-AS-EU and the 2021 Settlement Agreement (2021 Settlement) approved by the

Commission in Order No. PSC-2021-0202-AS-EI.[1] Pursuant to Order No. PSC-2021-0425-FOF-EI (2021 Rate Mitigation Agreement), DEF charged the remaining uncollected storm restoration costs resulting from Hurricanes Eta and Isaias, estimated at $9.2 million, to the storm reserve, while reserving the right to collect the remainder of the unrecovered storm cost balance at a later time.[2] DEF also voluntarily agreed to forego recovering costs related to Hurricane Elsa through a storm surcharge and instead reserved the right to collect an estimated $15 to $18 million of storm restoration costs at a later date. As a result of the 2021 Rate Mitigation Agreement, DEF deferred collection of approximately $24.4 million in storm-related costs. DEF is now seeking to recover those costs as part of its petition. Pursuant to the 2017 Settlement and 2021 Settlement, the Company can recover storm costs, without a cap on the level of charges on customer bills, on an interim basis beginning 60 days following the filing of a petition for recovery. DEF has proposed interim storm restoration charges applicable to all rate classes over a 12-month recovery period, effective with the first billing cycle of April 2023.

The Commission has jurisdiction over this matter pursuant to Sections 366.04, 366.05, 366.06, and 366.076, Florida Statutes.

[1]Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170183-EI, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.* and Order No. PSC-2021-0202-AS-EI, issued June 4, 2021, in Docket No. 20210016-EI, *In re: Petition for limited proceeding to approve 2021 settlement agreement, including general base rate increases, by Duke Energy Florida, LLC.*
[2]Order No. PSC-2021-0425-FOF-EI, issued November 16, 2021, in Docket No. 20210158-EI, *In re: Limited proceeding to consider Duke Energy Florida, LLC's unopposed motion to approve rate mitigation agreement.*

Discussion of Issues

Issue 1: Should the Commission authorize DEF to implement an interim storm restoration recovery charge?

Recommendation: Yes. The Commission should authorize DEF to implement an interim storm restoration recovery charge, subject to refund. Once the total actual storm costs are known, DEF should be required to file documentation of the total storm costs for Commission review and true-up of any excess or shortfall. (Snyder)

Staff Analysis: DEF filed a petition for a limited proceeding seeking authority to implement an interim storm restoration recovery charge to recover $442.1 million for the incremental restoration costs related to Hurricanes Elsa, Eta, Ian, Isaias, Nicole and Tropical Storm Fred, and to replenish its storm reserve. In its petition, DEF requested to replenish the storm reserve to $131.9 million.

The petition was filed pursuant to the provisions of the 2017 Settlement approved by the Commission in Order No. PSC-2017-0451-AS-EU and 2021 Settlement approved by the Commission in Order No. PSC-2021-0202-AS-EI.[3] Storm restoration costs for Eta, Elsa, Isaias, and Fred were incurred while the 2017 Settlement Agreement was in effect. Storm restoration costs for Ian and Nicole were incurred during the term of the 2021 Settlement Agreement. The Storm Cost Recovery provisions of the respective Settlement Agreements are identical. Pursuant to Paragraph 38 of the 2017 Settlement and Paragraph 30c of the 2021 Settlement, DEF can begin recovery of storm costs, without a cap, 60 days following the filing of a petition for recovery. DEF has proposed an interim storm recovery charge of $13.14 per 1,000 kilowatt-hours (kWh) on a residential customer bill over a 12-month recovery period effective the first billing cycle of April 2023.

In its petition, DEF asserted that it incurred total retail recoverable costs of approximately $442.1 million as a result of Hurricanes Elsa, Eta, Ian, Isaias, and Nicole and Tropical Storm Fred, as well as to replenish its storm reserve. The Company further asserted that this amount was calculated in accordance with the Incremental Cost and Capitalization Approach methodology prescribed in Rule 25-6.0143, Florida Administrative Code (F.A.C.).

The approval of an interim storm restoration recovery charge is preliminary in nature and is subject to refund pending further review once the total actual storm restoration costs are known. After the actual costs are reviewed for prudence and reasonableness, and are compared to the actual amount recovered through the interim storm restoration recovery charge, a determination will be made whether any over/under recovery has occurred. The disposition of any over/under recovery, and associated interest, will be considered by the Commission at a later date.

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[3]Order No. PSC-2017-0451-AS-EU, issued November 20, 2017, in Docket No. 20170183, *In re: Application for limited proceeding to approve 2017 second revised and restated settlement agreement, including certain rate adjustments, by Duke Energy Florida, LLC.* and Order No. PSC-2021-0202-AS-EI, issued June 4, 2021, in Docket No. 20210016-EI, *In re: Petition for limited proceeding to approve 2021 settlement agreement, including general base rate increases, by Duke Energy Florida, LLC.*

Based on a review of the information provided by DEF in its petition, staff recommends that the Commission authorize the Company to implement an interim storm restoration recovery charge subject to refund. Once the total actual storm costs are known, DEF should be required to file documentation of the storm costs for Commission review and true-up of any excess or shortfall.

Issue 2: What is the appropriate security to guarantee the amount collected subject to refund through the interim storm restoration recovery charge?

Recommendation: The appropriate security to guarantee the funds collected subject to refund is a corporate undertaking. (D. Buys)

Staff Analysis: Staff recommends that all funds collected subject to refund be secured by a corporate undertaking. The criteria for a corporate undertaking include sufficient liquidity, ownership equity, profitability, and interest coverage to guarantee any potential refund. DEF requested a 12-month collection period from April 2023 to March 2024 for Interim Storm Cost Recovery Charges of $442,074,721 related to Hurricanes Elsa, Eta, Ian, Isaias, Nicole and Tropical Storm Fred. Staff reviewed DEF's three most recent annual reports filed with the Commission (2021, 2020, and 2019) to determine if the Company can support a corporate undertaking to guarantee the funds collected for recovery of incremental storm restoration costs related to all the weather events. DEF's financial information indicates the Company's liquidity is deficient, that is, that current assets are less than current liabilities. However, the Company participates in Duke Energy Corporation's (DEF's parent company) money pool and has access to additional funds if needed. In addition, DEF's ownership equity, profitability, and interest coverage are sufficient to support a potential refund of $442 million. Moreover, it is improbable DEF will be required to refund the entire requested amount.

Staff believes that DEF has adequate resources to support a corporate undertaking in the amount requested. Therefore, staff recommends that a corporate undertaking of $442 million is acceptable. This brief financial analysis is only appropriate for deciding if the Company can support a corporate undertaking in the amount proposed and should not be considered a finding regarding staff's position on other issues in this proceeding.

Issue 3: Should the Commission approve DEF's proposed interim storm restoration recovery charge tariff as shown in Attachment A to this recommendation?

Recommendation: Yes. The Commission should approve DEF's proposed interim storm restoration recovery charge tariff, as shown in Attachment A to this recommendation, effective with the first billing cycle of April 2023 and ending the earlier of full recovery or with the last billing cycle of March 2024, whichever occurs first. The interim storm restoration recovery charge should be subject to a final true-up. (Hampson)

Staff Analysis: DEF is seeking approval of interim storm cost recovery surcharges associated with Hurricanes Elsa, Eta, Isaias, Ian, Nicole, and Tropical Storm Fred as shown in proposed Tariff Sheet Nos. 6.105 and 6.106 (Attachment A to this recommendation). The surcharges would be applicable to all rate classes. Tariff Sheet No 6.105 indicates the proposed interim storm cost recovery surcharges and Tariff Sheet No. 6.106 defines the storm cost recovery surcharge.

DEF explained that it has allocated the storm cost recovery amount to the rate classes consistent with the rate design approved in the 2021 Settlement.[4] Staff reviewed the storm cost recovery allocation and calculation of rates and it appears that DEF has calculated rates in accordance with the 2021 Settlement, using the most recent load research study and projected billing determinants for the recovery period.

The interim storm restoration recovery charge calculations are shown on pages 9 and 10 in Appendix A to DEF's petition. For residential customers, the surcharge would be 1.314 cents per kWh, which would equate to $13.14 on a 1,000 kWh residential bill. If approved by the Commission, the storm cost recovery surcharge would be included in the non-fuel energy charge on customer bills.

CONCLUSION

Staff recommends that the Commission approve DEF's proposed interim storm restoration recovery charge tariff, as shown in Attachment A to this recommendation, effective with the first billing cycle of April 2023 and ending the earlier of full recovery or with the last billing cycle of March 2024, whichever occurs first. Furthermore, the interim storm restoration recovery charge should be subject to a final true-up.

[4] Order No. PSC-2021-0202-AS-EI, issued June 4, 2021, in Docket No. 20210016-EI, *In re: Petition for limited proceeding to approve 2021 settlement agreement, including general base rate increases, by Duke Energy Florida, LLC.*

Issue 4: Should this docket be closed?

Recommendation: No. This docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted. (Brownless)

Staff Analysis: No, this docket should remain open pending final reconciliation of actual recoverable storm costs with the amount collected pursuant to the interim storm restoration recovery charge and the calculation of a refund or additional charge if warranted.

DUKE ENERGY

SECTION NO. VI
ONE HUNDRED AND FIRST~~TH~~ REVISED SHEET NO. 6.105
CANCELS ~~NINETY-NIN~~ONE HUNDREDTH REVISED SHEET NO. 6.105

RATE SCHEDULE BA-1
BILLING ADJUSTMENTS

Applicable:

To the Rate Per Month provision in each of the Company's filed rate schedules which reference the billing adjustments set forth below.

COST RECOVERY FACTORS

Rate Schedule/Metering Level	ECCR[2]		CCR[3]		ECRC[4]	ASC[5]	SPPCRC[6]		SCRS[7]
	¢/ kWh	$/ kW	¢/ kWh	$/ kW	¢/ kWh	¢/ kWh	¢/ kWh	$/ kW	¢/ kWh
RS-1, RST-1, RSL-1, RSL-2 (Sec.) < 1000 > 1000	0.320	-	~~1.328~~1.285	-	0.022	0.199	0.414	-	-1.314
GS-1, GST-1									
Secondary	0.288	-	~~1.173~~1.138	-	0.021	0.175	0.401	-	-1.312
Primary	0.285	-	~~1.161~~1.127	-	0.021	0.173	0.397	-	-1.299
Transmission	0.282	-	~~1.150~~1.115	-	0.021	0.172	0.393	-	-1.286
GS-2 (Sec.)	0.217	-	~~0.822~~0.795	-	0.018	0.124	0.188	-	-0.582
GSD-1, GSDT-1, SS-1*									
Secondary	-	0.85	-	~~3.37~~3.26	0.020	0.151	-	1.05	-0.941
Primary	-	0.84	-	~~3.34~~3.23	0.020	0.149	-	1.01	-0.932
Transmission	-	0.83	-	~~3.30~~3.19	0.020	0.148	-	0.19	-0.922
CS-2, CST-2, CS-3, CST-3, SS-3*									
Secondary	-	0.46	-	~~1.67~~1.61	0.016	0.097	-	0.98	-1.611
Primary	-	0.46	-	~~1.65~~1.59	0.016	0.096	-	0.97	-1.595
Transmission	-	0.45	-	~~1.64~~1.58	0.016	0.095	-	0.96	-1.579
IS-2, IST-2, SS-2*									
Secondary	-	0.70	-	~~2.69~~2.60	0.018	0.124	-	0.80	-0.421
Primary	-	0.69	-	~~2.66~~2.57	0.018	0.123	-	0.59	-0.417
Transmission	-	0.69	-	~~2.64~~2.55	0.018	0.122	-	0.14	-0.413
LS-1 (Sec.)	0.116	-	~~0.341~~0.330	-	0.014	0.050	0.306	-	-1.166
*SS-1, SS-2, SS-3									
Monthly									
Secondary	-	0.082	-	~~0.325~~0.314	-	-	-	0.094	-
Primary	-	0.081	-	~~0.322~~0.311	-	-	-	0.093	-
Transmission	-	0.080	-	~~0.319~~0.308	-	-	-	0.092	-
Daily									
Secondary	-	0.039	-	~~0.155~~0.150	-	-	-	0.045	-
Primary	-	0.039	-	~~0.153~~0.148	-	-	-	0.045	-
Transmission	-	0.038	-	~~0.152~~0.147	-	-	-	0.044	-
GSLM-1, GSLM-2	See appropriate General Service rate schedule								

Fuel Cost Recovery[1]

Rate Schedule/Metering Level		Levelized	On-Peak	Off-Peak	Super-Off-Peak
		¢/ kWh	¢/ kWh	¢/ kWh	¢/ kWh
RS-1 Only	**< 1,000**	~~5.961~~7.953	N/A	N/A	N/A
RS-1 Only	**> 1,000**	~~7.031~~9.023	N/A	N/A	N/A
LS-1 Only	**Secondary**	~~5.865~~7.751	N/A	N/A	N/A
All Other Rate Schedules	**Secondary**	~~6.266~~8.281	~~7.695~~10.169	~~6.304~~8.331	~~4.674~~6.178

ISSUED BY: Thomas G. Foster, Vice President, Rates & Regulatory Strategy – FL

EFFECTIVE: ~~March 1, 2023~~April 1, 2023

DUKE ENERGY

SECTION NO. VI
ONE HUNDRED AND FIRST~~TH~~ REVISED SHEET NO. 6.105
CANCELS ~~NINETY-NIN~~ONE HUNDREDTH REVISED SHEET NO. 6.105

All Other Rate Schedules	Primary	~~6.203~~8.198	~~7.617~~10.067	~~6.240~~8.247	~~4.627~~6.116
All Other Rate Schedules	Transmission	~~6.141~~8.115	~~7.541~~9.965	~~6.178~~8.164	~~4.581~~6.054

(Continued on Page No. 2)

ISSUED BY: Thomas G. Foster, Vice President, Rates & Regulatory Strategy – FL
EFFECTIVE: ~~March 1, 2023~~April 1, 2023

RATE SCHEDULE BA-1
BILLING ADJUSTMENTS
(Continued from Page 1)

(1) Fuel Cost Recovery Factor:

The Fuel Cost Recovery Factors applicable to the Fuel Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. These factors are designed to recover the costs of fuel and purchased power (other than capacity payments) incurred by the Company to provide electric service to its customers and are adjusted to reflect changes in these costs from one period to the next. Revisions to the Fuel Cost Recovery Factors within the described period may be determined in the event of a significant change in costs.

(2) Energy Conservation Cost Recovery Factor:

The Energy Conservation Cost Recovery (ECCR) Factor applicable to the Energy Charge under the Company's various rate schedules is normally determined annually by the Florida Public Service Commission for twelve-month periods beginning with the billing month of January. This factor is designed to recover the costs incurred by the Company under its approved Energy Conservation Programs and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the ECCR charge will be included in the monthly max demand only.

(3) Capacity Cost Recovery Factor:

The Capacity Cost Recovery (CCR) Factors applicable to the Energy Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. This factor is designed to recover the cost of capacity payments made by the Company for off-system capacity and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the CCR charge will be included in the monthly max demand only.

(4) Environmental Cost Recovery Clause Factor:

The Environmental Cost Recovery Clause (ECRC) Factors applicable to the Energy Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. This factor is designed to recover environmental compliance costs incurred by the Company and is adjusted to reflect changes in these costs from one period to the next.

(5) Asset Securitization Charge Factor:

The Asset Securitization Charge (ASC) Factors applicable to the Energy Charge under the Company's various rate schedules represent a Nuclear Asset-Recovery Charge approved in a financing order issued to the Company by the Florida Public Service Commission and are adjusted at least semi-annually to ensure timely payment of principal, interest and financing costs of nuclear asset-recovery bonds from the effective date of the ASC until the nuclear asset-recovery bonds have been paid in full or legally discharged and the financing costs have been fully recovered. As approved by the Commission, a Special Purpose Entity (SPE) has been created and is the owner of all rights to the Nuclear Asset-Recovery Charge. The Company shall act as the SPE's collection agent or servicer for the Nuclear Asset-Recovery Charge. The Nuclear Asset-Recovery Charge shall be paid by all existing or future customers receiving transmission or distribution service from the Company or its successors or assignees under Commission-approved rate schedules or under special contracts, even if the customer elects to purchase electricity from alternative electric suppliers following a fundamental change in regulation of public utilities in this state.

(6) Storm Protection Plan Cost Recovery Clause Factor:

The Storm Protection Plan Cost Recovery Clause (SPPCRC) Factors applicable to the Energy Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. This factor is designed to recover storm protection plan costs incurred by the Company and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the SPPCRC charge will be included in the monthly max demand only.

(7) Storm Cost Recovery Surcharge Factor:

In accordance with a Florida Public Service Commission ruling, the Storm Cost Recovery Surcharge (SCRS) factor is applicable to the Energy Charge under the Company's various rate schedules for the billing months of ~~August 2021 through July 2022~~April 2023 through March 2024. This surcharge is designed to recover storm~~-related~~ restoration costs, replenishment of the storm reserve, and interest ~~incurred by the Company~~ related to Hurricanes ~~Eta and Isaias in 2020~~Elsa, Eta, Ian, Isaias, Nicole, and Tropical Storm Fred.

Gross Receipts Tax Factor:

In accordance with Section 203.01(1)(a)1 of the Florida Statutes, a factor of 2.5641% is applicable to electric sales charges for collection of the state Gross Receipts Tax.

Regulatory Assessment Fee Factor:

In accordance with Section 350.113 of the Florida Statutes and Rule 25-6.0131, F.A.C., a factor of 0.072% is applicable to gross operating sales charges for collection of the Regulatory Assessment Fee.

(Continued on Page No. 3)

ISSUED BY: Thomas G. Foster, Vice President, Rates & Regulatory Strategy – FL

EFFECTIVE: ~~January 1, 2023~~April 1, 2023

Item 6

REVISED 03/02/23

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: March 1, 2023

TO: Adam J. Teitzman, Commission Clerk, Office of Commission Clerk

FROM: Andrew L. Maurey, Director, Division of Accounting & Finance

RE: Revised Recommendation - Docket No. 20230001-EI (Item 6)

On January 23, 2023, Duke Energy Florida, LLC (DEF) filed a petition requesting a mid-course correction of both its 2023 fuel and capacity cost recovery factors. This petition was amended on February 27, 2023. The revised recommendation addresses DEF's amended petition.

State of Florida

Public Service Commission

**Capital Circle Office Center ● 2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850**

-M-E-M-O-R-A-N-D-U-M-

DATE: March 2, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (Higgins, Kelley, Zaslow) ALM
Division of Economics (Hampson) JGH
Office of the General Counsel (Brownless, Sandy) JSC

RE: Docket No. 20230001-EI – Fuel and purchased power cost recovery clause with generating performance incentive factor.

AGENDA: 03/07/23 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On January 23, 2023, Duke Energy Florida, LLC (DEF or Company), filed for a mid-course correction of both its 2023 fuel and capacity cost recovery factors.[1] This petition was amended on February 27, 2023 (MCC Petition).[2] DEF's currently-effective 2023 fuel and capacity factors were approved last year at the November 17-18, and December 6, 2022 final hearing.[3] Underlying the approval of DEF's 2023 factors was the Florida Public Service Commission's (Commission) review of the Company's projected 2023 fuel- and capacity-related costs. These costs are recovered through fuel and capacity cost recovery factors that are set/reset annually in this docket. However, during the 2022 annual fuel clause cycle, DEF proposed not to include the

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[1]Document No. 00417-2023.
[2]Document No. 01366-2023.
[3]Order No. PSC-2023-0026-FOF-EI, issued January 6, 2023, in Docket No. 20230001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.

majority of its unrecovered 2022 fuel costs in the fuel factors approved at the December 6th final hearing. Instead, DEF indicated it would be petitioning for recovery of those costs through a separate filing. The primary rationale for this course of action was that the extreme volatility of natural gas prices in 2022 had made a reliable projection of final 2022 costs impractical. The Commission subsequently ordered DEF's filing to be submitted on or before January 23, 2023.[4]

Mid-Course Corrections

Mid-course corrections are used by the Commission between annual clause hearings whenever costs deviate from revenue by a significant margin. Under Rule 25-6.0424, Florida Administrative Code (F.A.C.), which is commonly referred to as the "mid-course correction rule," a utility must notify the Commission whenever it expects to experience an under- or over-recovery of certain service costs greater than 10 percent. The notification of a 10 percent cost-to-revenue variance shall include a petition for mid-course correction to the fuel cost recovery or capacity cost recovery factors, or shall include an explanation of why a mid-course correction is not practical. The mid-course correction rule and its codified procedures are further discussed throughout this recommendation.

DEF's Petition for Mid-Course Correction

Through its MCC Petition, DEF is proposing a mid-course correction of its 2023 fuel and capacity charges. Specifically, the Commission is being asked to approve increases to DEF's fuel cost recovery factors to incorporate its currently-projected 2023 end-of-year fuel cost under-recovery in the amount of approximately $469 million. With respect to capacity costs, the Company is proposing to incorporate into rates the 2022 tax-savings effect of the Inflation Reduction Act (IRA) of 2022 in the amount of approximately $11.7 million.[5] This topic is discussed further in Issue 1.

The Company is requesting that its revised fuel and capacity factors and associated tariff sheet No. 6.105 become effective beginning with the first billing cycle of April 2023. The effective date is further discussed in both Issues 1 and 2. Also included in the Company's proposed tariff are the (proposed) rate adjustments related to its recovery of storm restoration (to include reserve replenishment) costs related to Hurricanes: Elsa, Eta, Ian, Isaias, and Nicole, and Tropical Storm Fred, as petitioned for in Docket No. 20230020-EI.[6] However, while the rate adjustments are addressed on proposed tariff sheets No. 6.105 and No. 6.106 in Appendix A to this recommendation, neither the Interim Storm Charge or associated rates are at issue in this proceeding.

The Commission is vested with jurisdiction over the subject matter of this proceeding by the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

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[4]Order No. PSC-2023-0026-FOF-EI.
[5]Retroactively effective to January 1, 2022, the IRA expanded federal income tax benefits for renewable energy by allowing owners of solar projects which begin construction before 2025 the option to elect to receive Production Tax Credits rather than Investment Tax Credits for eligible facilities. The tax savings noted through-out this recommendation were produced by the Company electing to record Production Tax Credits rather than Investment Tax Credits for eligible facilities.
[6]See Document No. 00418-2023 for further information regarding DEF's Interim Storm Charge request.

Discussion of Issues

Issue 1: Should the Commission modify DEF's currently-approved fuel and capacity cost recovery factors for the purpose of incorporating its actual 2022 under-recovery of fuel costs?

Recommendation: Yes. Staff recommends the Commission approve DEF's proposed adjustments to its currently-approved fuel cost recovery factors to incorporate the currently-projected 2023 end-of-year fuel cost under-recovery in the amount of $468,961,606. Further, staff recommends the Commission approve adjustments to DEF's currently-approved capacity cost recovery factors to incorporate a refund of ($11,668,131) related to the tax savings associated with the IRA of 2022. (Higgins, Zaslow, Kelley)

Staff Analysis: DEF participated in the Commission's most-recent fuel hearing which took place during November 17-18, 2022, and December 6, 2022. The fuel order stemming from this proceeding set forth the Company's fuel and capacity cost recovery factors effective with the first billing cycle of January 2023.[7] However, as discussed below, the currently-authorized fuel cost recovery factors do not include certain deferred fuel costs that were primarily incurred in 2022. In support of the deferral, DEF argued that the 2022 natural gas market was so volatile that its total annual fuel (natural gas) cost could not be accurately predicted and that it was better to wait and use actual costs for setting rates with respect to the 2022 under-recovery. Some factors that influenced natural gas prices in 2022 include reduced storage levels, strong liquefied natural gas exports, global military conflict, and capital/expenditure discipline being practiced by drilling companies.

DEF Fuel and Purchased Power Mid-Course Correction

DEF filed for a mid-course correction of its fuel and capacity charges on January 23, 2023.[8] This filing was amended on February 27, 2023.[9] The Company's amended petition and supporting documentation satisfy the filing requirements of Rule 25-6.0424(1)(b), F.A.C. In accordance with the noticing requirement of Rule 25-6.0424(2), F.A.C., DEF filed a letter on March 29, 2022, informing the Commission that it was projecting an under-recovery position of greater than 10 percent for the recovery period ending on December 31, 2022.[10] However, in analyzing settlement prices for natural gas, the Company determined that the continuing price volatility warranted deferring a decision to file for a mid-course correction.

The Company developed its proposed mid-course correction factors using twelve months of forecasted sales data (April 2023 through March 2024). However, the exact factors proposed in this proceeding are currently contemplated to be charged for 9 months in 2023. As is typical procedure, later this year newly developed 12-month-applicable factors will be proposed for authorization to begin with the first billing cycle of January 2024.

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[7]Order No. PSC-2023-0026-FOF-EI.
[8]Document No. 00417-2023.
[9]Document No. 01366-2023.
[10]Document No. 02134-2022.

DEF Capacity Mid-Course Correction

As previously mentioned, DEF filed for a mid-course adjustment of its capacity charges along with its fuel mid-course correction. Staff notes that DEF's capacity proposal is not being driven by a cost recovery position outside the absolute value of 10 percent as calculated using the methodology prescribed in Rule 25-6.0424(1)(a), F.A.C., rather, the driver or purpose of this proposed change is to expeditiously return to customers the benefit of the 2022 tax savings produced by the IRA. The estimated 2022 tax benefit is $11,668,131, and constitutes the amount DEF proposes to reduce 2023 capacity costs by in this proceeding. As contemplated and proposed, this amount will be refunded over a 9-month period, or from April through December 2023.

Actual Period-Ending 2022 Fuel Cost Recovery Position

DEF's actual fuel cost recovery position at the end of 2022 is an under-recovery of ($1,354,975,755), of which $175,789,361 has been previously incorporated into 2023 rates.[11] This $175,789,361 amount consists of the second half, or $123,418,788, associated with the "Rate Mitigation Agreement" between DEF and the Office of Public Counsel, the Florida Industrial Power Users Group, the Florida Retail Federation, Nucor Steel Florida, Inc., the Southern Alliance for Clean Energy, and White Springs Agricultural Chemicals, Inc. d/b/a PCS Phosphate.[12] The first half of the Rate Mitigation Agreement amount was collected in 2022. The remainder, or $52,370,573, represents the carry forward from DEF's previous, or 2022 mid-course correction proceeding.[13]

Increased pricing for natural gas was the primary driver of the 2022 under-recovery discussed above. More specifically, the Company estimated an annual natural gas cost of $5.20 per million British thermal unit (MMBtu) in its last mid-course correction filing and derivation of 2022 customer fuel rates.[14] This figure includes delivery costs. However, as indicated in the Company's December 2022 A-Schedule, DEF's average 2022 cost of natural gas was $8.50 per MMBtu, representing a difference of 63.5 percent.[15] Natural gas-fired generation comprised approximately 85.7 percent of DEF's generation mix in 2022.[16]

Projected 2023 Fuel Cost Recovery Position

DEF's 2023 fuel-related revenue requirement decreased substantially since the filing of its last cost projection in September 2022.[17] More specifically, the results of this updated projection are a reduction in DEF's estimated 2023 fuel-related costs in the amount of $710,224,788. Thus,

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[11]Order No. PSC-2023-0026-FOF-EI.

[12]See Document No. 10082-2021, filed in Docket No. 20210001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*, Docket No. 20210097-EI, *In re: Petition for Limited Proceeding for Recovery of Incremental Storm Restoration Costs Related to Hurricane Eta and Isaias, by Duke Energy Florida, LLC*, and Docket No. 20210010-EI, *In re: Storm Protection Plan Cost Recovery Clause*. This motion was ultimately adjudicated in Docket No. 20210158-EI.

[13]Order No. PSC-2022-0061-PCO-EI, issued February 17, 2022, in Docket No. 20220001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.

[14]Document No. 13092-2021.

[15]Document No. 00282-2023.

[16]*Id*.

[17]Document No. 05978-2022.

given the net carry forward from 2022 discussed above, the proposed incremental amount for inclusion into rates is ($468,961,606).

The primary factor driving the change in projected 2023 fuel costs is lower assumed pricing for natural gas. More specifically, the underlying market-based natural gas price data used for the original 2023 fuel cost projection was sourced on June 13, 2022.[18] This data was used to produce an estimated average 2023 delivered natural gas cost of $8.07 per MMBtu.[19] However, as indicated in its MCC Petition, DEF now estimates its average cost of natural gas in 2023 will be $4.76 per MMBtu, representing a decrease of 41.0 percent.[20] The updated cost estimate was based on natural gas futures/prices sourced on February 14, 2023, or roughly eight months later than the previous estimate used to set current rates.[21]

Recovery Period and Interest Premium

As proposed, DEF's recovery period for its 2022 under-recovery of fuel costs is over 12 months of sales (beginning April 2023 and ending March 2024).[22] DEF utilized the 30-day AA Financial Commercial Paper Rate to determine its 2022 interest amount.[23] The projected 2023 monthly interest rate was estimated for all months by using the January 2023 average of the 30-day AA Financial Commercial Paper Rate of 0.374 percent.[24]

Mid-Course Correction Percentage

Following the methodology prescribed in Rule 25-6.0424(1)(a), F.A.C., the mid-course percentage is equal to the estimated end-of-period total net true-up, including interest, divided by the current period's total actual and estimated jurisdictional fuel revenue applicable to period, or ($468,961,606) / $2,281,046,501.[25] This calculation results in a mid-course correction level of (20.6) percent at December 31, 2023.

Fuel Factor

DEF's currently-approved annual levelized fuel factor beginning with the first January 2023 billing cycle is 6.257 cents per kilowatt-hour (kWh).[26] The Company is requesting to increase its currently-approved 2023 annual levelized fuel factor beginning April 2023 to 7.445 cents per kWh, or by 19.0 percent.[27]

[18]Document No. 01366-2023.
[19]Document No. 05978-2022.
[20]Document No. 01366-2023.
[21]*Id*.
[22]Document No. 01366-2023.
[23]Document No. 00864-2023.
[24]Document Nos. 00864-2023 and 01368-2023, and The Federal Reserve System (U.S. Federal Reserve) published Commercial Paper Rates which can be located via the following link: https://www.federalreserve.gov/releases/cp/
[25]The estimated end-of-period total net true-up, or the mid-course correction amount being sought for recovery in this proceeding, consists of the 2022 under-recovery of ($1,354,975,755), the Rate Mitigation Plan amount for 2023 of $123,418,788, the 2022 mid-course correction carry forward amount of $52,370,573, and the change in projected 2023 fuel-related costs of $710,224,788, for a total of ($468,961,606).
[26]Order No. PSC-2023-0026-FOF-EI.
[27]Document No. 01366-2023.

Bill Impacts

Table 1-1 below shows the bill impact to a typical residential customer using 1,000 kWh of electricity a month associated with the current and proposed service charges. This table also includes the storm-related cost recovery proposal that, if approved, would begin in April 2023.[28] In the discussion directly below Table 1-1, staff discusses the impacts of the proposed MCC on non-residential customers:

Table 1-1
Monthly Residential Billing Detail for the First 1,000 kWh

Invoice Component	Currently-Approved Charges Beginning March 2023 ($)	Proposed Charges Beginning April 2023 ($)	Difference ($)	Difference (%)
Base Charge[29]	$78.82	$78.82	$0.00	0.0%
Fuel Charge	59.61	71.27	11.66	19.6%
Capacity Charge	13.28	12.85	(0.43)	(3.2%)
Conservation Charge	3.20	3.20	0.00	0.0%
Environmental Charge	0.22	0.22	0.00	0.0%
Storm Protection Plan Charge	4.14	4.14	0.00	0.0%
Interim Storm Charge[30]	0.00	13.14	13.14	100.0%
Asset Securitization Charge	2.03	2.03	0.00	0.0%
Gross Receipts Tax	4.25	4.89	0.64	15.1%
Total	$165.55	$190.56	$25.01	15.1%

Source: MCC Petition, Schedule E-10, and FPSC Division of Economics.

DEF's current total residential bill for the first 1,000 kWh of electricity usage in March of 2023 is $165.55. If DEF's mid-course correction proposal is approved, the current total residential bill for the first 1,000 kWh of electricity usage, beginning April 2023, will be $190.56. Staff notes this amount includes the proposed interim storm charge as filed in Docket No. 20230020-EI. This represents an increase of 15.1 percent. For non-residential customers, DEF reported that based on average levels of usage and specific rate schedules, bill increases for small- and medium-size commercial customers would be 15.0 percent and 15.5 percent, respectively, bill increases for large-size commercial customers would be 16.6 percent, and 17.7 percent for industrial customers.[31] DEF's proposed tariff sheet No. 6.105 is shown on Appendix A to this recommendation.

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[28]Document No. 00418-2023.
[29]DEF's 2023 base rates for December 2022 – February 2023 is $89.39; for March 2023 – November 2023 is $78.82. The weighted average is equal to: (($89.39 * 3) + (78.82 * 9)) / 12 = $81.46.
[30]Subject to Commission approval in Docket No. 20230020-EI.
[31]Document No. 01394-2023.

Optional Recovery

Staff investigated the effect on monthly bills of lengthening the proposed recovery period from 12 to 21 months. For recovery purposes, the total base/unrecovered 2022 fuel cost to collect is the same under the 21-month scenario; however, the impact can be characterized as a lower monthly fuel charge for a longer period of time/greater number of months. However, this optional recovery would result in increased carrying charges.

Table 1-2 below shows the bill impact to a typical residential customer using 1,000 kWh of electricity a month associated with the optional recovery scenario described in this section of the recommendation.

Table 1-2
Optional Monthly Residential Billing Detail for the First 1,000 kWh

Invoice Component	Currently-Approved Charges Beginning March 2023 ($)	Optional Charges Beginning April 2023 ($)	Difference ($)	Difference (%)
Base Charge[32]	$78.82	$78.82	$0.00	0.0%
Fuel Charge	59.61	53.02	(6.59)	(11.1%)
Capacity Charge	13.28	12.85	(0.43)	(3.2%)
Conservation Charge	3.20	3.20	0.00	0.0%
Environmental Charge	0.22	0.22	0.00	0.0%
Storm Protection Plan Charge	4.14	4.14	0.00	0.0%
Interim Storm Charge[33]	0.00	13.14	13.14	100.0%
Asset Securitization Charge	2.03	2.03	0.00	0.0%
Gross Receipts Tax	4.25	4.41	0.16	3.8%
Total	$165.55	$171.83	$6.28	3.8%

Source: Document No. 01387-2023, Schedule E-10.

DEF's proposed fuel charge increase results in a "first-tier residential" fuel charge, (i.e., residential charge for the first 1,000 kWh of energy sales) of 7.127 cents per kWh. This factor produces a corresponding monthly fuel charge of $71.27. With respect to the optional recovery scenario, the first-tier residential factor would be 5.302 cents per kWh.[34] This would result in a fuel charge of $53.02 for the first 1,000 kWh of energy usage. The estimated decrease in the monthly first-tier residential fuel charge (1,000 kWh) under this scenario is approximately ($6.59), or a (11.1) percent decrease from the currently-approved level, going from $59.61 to

[32]DEF's 2023 base rates for December 2022 – February 2023 is $89.39; for March 2023 – November 2023 is $78.82. The weighted average is equal to: (($89.39 * 3) + (78.82 * 9)) / 12 = $81.46.
[33]Subject to Commission approval in Docket No. 20230020-EI.
[34]Document No. 01387-2023.

$53.02. The difference in total bill amount (first-tier residential - 1,000 kWh), which encompasses all proposed changes beginning in April 2023, is from $190.56 to $171.83, or a reduction of (9.8) percent if the fuel cost under-recovery is spread over 21 months, rather than the proposed 12 months. The proposed capacity cost recovery reduction would be unaffected by the optional recovery scenario.

For non-residential customers, based on average levels of usage and specific rate schedules, bill increases for small- and medium-size commercial customers would be 3.9 percent and 2.0 percent, respectively, bill increases for large-size commercial customers would be 2.3 percent, and (2.5) percent for industrial customers.[35] The hypothetical tariff associated with the optional recovery scenario was provided in the amended response to Staff's Third Data Request (Response No. 3).[36] However, the tariff was not included as an attachment to this recommendation.

Summary

DEF's MCC Petition indicates a need for its fuel cost recovery factors to be revised. Thus, DEF's current fuel cost recovery factors should be adjusted by $468,961,606 to incorporate its currently-projected 2023 end-of-year fuel cost under-recovery. Additionally, DEF's currently-approved capacity cost recovery factors should be amended to incorporate a refund of ($11,668,131). The revised fuel and capacity cost recovery factors associated with staff's recommendations are shown on Appendix A.

Conclusion

Staff recommends that the Commission approve DEF's proposed adjustments to its currently-approved fuel cost recovery factors to incorporate the currently-projected 2023 end-of-year fuel cost under-recovery in the amount of $468,961,606. Further, staff recommends that the Commission approve adjustments to DEF's currently-approved capacity cost recovery factors to incorporate a refund of ($11,668,131) related to the tax savings associated with the IRA of 2022.

[35]Document No. 01394-2023.
[36]*Id*.

Issue 2: If approved by the Commission, what is the appropriate effective date for DEF's revised fuel and capacity cost recovery factors?

Recommendation: The fuel and capacity cost recovery factors, as shown on sheet No. 6.105 in Appendix A, should become effective with the first billing cycle of April 2023. (Hampson, Brownless, Sandy)

Staff Analysis: Over the last 20 years in the Fuel Clause docket, the Commission has considered the effective date of rates and charges of revised fuel cost recovery factors on a case-by-case basis. The Commission has approved fuel cost recovery factor rate decreases effective sooner than the next full billing cycle after the date of the Commission's vote with the range between the vote and the effective date being from 25 to 2 days. The rationale for that action being that it was in the customers' best interests to implement the lower rate as soon as possible.[37]

With regard to fuel cost recovery factor rate increases, the Commission has approved an effective date of the revised factors ranging from 14 to 29 days after the vote.[38] The Commission noted that typically the utility had given its customers 30 days' written notice before the date of the vote that a fuel cost recovery factor increase had been requested and provided the proposed effective date of the higher fuel factors.

In its MCC Petition, DEF proposes to collect the actual 2022 under-recovery of fuel costs over 12 months, beginning with the first billing cycle of April 2023. The capacity cost reduction (2022 tax reduction) will occur over 9 months, or from April through December, 2023. In the

[37]Order No. PSC-08-0825-PCO-EI, issued December 22, 2008, in Docket No. 080001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-09-0254-PCO-EI, issued April 27, 2009, in Docket No. 090001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor;* Order No. PSC-11-0581-PCO-EI, issued on December 19, 2011, in Docket No. 110001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-12-0342-PCO-EI, issued July 2, 2012, in Docket No. 120001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-2012-0082-PCO-EI, issued February 24, 2012, in Docket No. 120001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-15-0161-PCO-EI, issued April 30, 2015, in Docket No. 150001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-2018-0313-PCO-EI, issued June 18, 2018, in Docket No. 20180001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order PSC-2020-0154-PCO-EI, issued May 14, 2020, in Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

[38]Order No. PSC-03-0381-PCO-EI, issued March 19, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-03-0382-PCO-EI, issued March 19, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-03-0400, issued March 24, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-03-0849-PCO-EI, issued July 22, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-09-0213-PCO-EI, issued April 9, 2009, in Docket No. 090001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor;* Order No. PSC-2019-0109-PCO-EI, issued March 22, 2019, in Docket No. 20190001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

instant case, there are 25 days between the Commission's vote on March 7th and the beginning of DEF's April 2023 billing cycle (April 1st).[39]

Concerning customer advisement of the instant request, DEF states that it will notify its customers of the proposed rate changes through bill inserts included with its March 2023 invoices. Additionally, on January 23, 2023, the same day DEF filed its original petition for mid-course correction, the Company posted a "press release" to its website, while also issuing the information to various media outlets describing the proposal.[40] An additional email will also be sent to large-account customers.

Conclusion

Staff recommends that the fuel and capacity cost recovery factors, as shown on sheet No. 6.105 in Appendix A, become effective with the first billing cycle of April 2023.

[39]Document No. 00864-2023.
[40]*Id*.

Issue 3: Should this docket be closed?

Recommendation: No. The 20230001-EI docket is an on-going proceeding and should remain open. (Brownless, Sandy)

Staff Analysis: The fuel docket is an on-going proceeding and should remain open.

DUKE ENERGY

SECTION NO. VI
ONE HUNDRED AND FIRST~~TH~~ REVISED SHEET NO. 6.105
CANCELS ~~NINETY-NIN~~ONE HUNDREDTH REVISED SHEET NO. 6.105

RATE SCHEDULE BA-1
BILLING ADJUSTMENTS

Applicable:
To the Rate Per Month provision in each of the Company's filed rate schedules which reference the billing adjustments set forth below.

COST RECOVERY FACTORS

Rate Schedule/Metering Level	ECCR(2)		CCR(3)		ECRC(4)	ASC(5)	SPPCRC(6)		SCRS(7)
	¢/ kWh	$/ kW	¢/ kWh	$/ kW	¢/ kWh	¢/ kWh	¢/ kWh	$/ kW	¢/ kWh
RS-1, RST-1, RSL-1, RSL-2 (Sec.) < 1000 > 1000	0.320	-	~~1.328~~1.285	-	0.022	0.199	0.414	-	-1.314
GS-1, GST-1									
Secondary	0.288	-	~~1.173~~1.138	-	0.021	0.175	0.401	-	-1.312
Primary	0.285	-	~~1.161~~1.127	-	0.021	0.173	0.397	-	-1.299
Transmission	0.282	-	~~1.159~~1.115	-	0.021	0.172	0.393	-	-1.286
GS-2 (Sec.)	0.217	-	~~0.832~~0.795	-	0.018	0.124	0.188	-	-0.582
GSD-1, GSDT-1, SS-1*									
Secondary	-	0.85	-	~~3.37~~3.26	0.020	0.151	-	1.05	-0.941
Primary	-	0.84	-	~~3.34~~3.23	0.020	0.149	-	1.01	-0.932
Transmission	-	0.83	-	~~3.30~~3.19	0.020	0.148	-	0.19	-0.922
CS-2, CST-2, CS-3, CST-3, SS-3*									
Secondary	-	0.46	-	~~1.67~~1.61	0.016	0.097	-	0.98	-1.611
Primary	-	0.46	-	~~1.65~~1.59	0.016	0.096	-	0.97	-1.595
Transmission	-	0.45	-	~~1.64~~1.58	0.016	0.095	-	0.96	-1.579
IS-2, IST-2, SS-2*									
Secondary	-	0.70	-	~~2.69~~2.60	0.018	0.124	-	0.80	-0.421
Primary	-	0.69	-	~~2.66~~2.57	0.018	0.123	-	0.59	-0.417
Transmission	-	0.69	-	~~2.64~~2.55	0.018	0.122	-	0.14	-0.413
LS-1 (Sec.)	0.116	-	~~0.341~~0.330	-	0.014	0.050	0.306	-	-1.166
*SS-1, SS-2, SS-3									
Monthly									
Secondary	-	0.082	-	~~0.325~~0.314	-	-	-	0.094	-
Primary	-	0.081	-	~~0.322~~0.311	-	-	-	0.093	-
Transmission	-	0.080	-	~~0.319~~0.308	-	-	-	0.092	-
Daily									
Secondary	-	0.039	-	~~0.155~~0.150	-	-	-	0.045	-
Primary	-	0.039	-	~~0.153~~0.148	-	-	-	0.045	-
Transmission	-	0.038	-	~~0.152~~0.147	-	-	-	0.044	-
GSLM-1, GSLM-2	See appropriate General Service rate schedule								

Fuel Cost Recovery(1)

Rate Schedule/Metering Level		Levelized	On-Peak	Off-Peak	Super-Off-Peak
		¢/ kWh	¢/ kWh	¢/ kWh	¢/ kWh
RS-1 Only	**< 1,000**	~~5.061~~7.127	N/A	N/A	N/A
RS-1 Only	**> 1,000**	~~7.031~~8.197	N/A	N/A	N/A
LS-1 Only	**Secondary**	~~5.865~~6.978	N/A	N/A	N/A
All Other Rate Schedules	**Secondary**	~~6.266~~7.455	~~7.605~~9.155	~~6.304~~7.500	~~4.674~~5.561

ISSUED BY: Thomas G. Foster, Vice President, Rates & Regulatory Strategy – FL

EFFECTIVE: ~~March 1, 2023~~April 1, 2023

SECTION NO. VI
ONE HUNDRED AND FIRST~~TH~~ REVISED SHEET NO. 6.105
CANCELS ~~NINETY-NIN~~ONE HUNDREDTH REVISED SHEET NO. 6.105

All Other Rate Schedules	Primary	~~6.203~~7.380	~~7.817~~9.063	~~6.240~~7.424	~~4.627~~5.505
All Other Rate Schedules	Transmission	~~6.141~~7.306	~~7.541~~8.972	~~6.178~~7.350	~~4.581~~5.450

(Continued on Page No. 2)

ISSUED BY: Thomas G. Foster, Vice President, Rates & Regulatory Strategy – FL

EFFECTIVE: ~~March 1, 2023~~April 1, 2023

DUKE ENERGY

SECTION NO. VI
THIRTY-~~THIRD~~ FOURTH REVISED SHEET NO. 6.106
CANCELS THIRTY-~~SECOND~~ THIRD REVISED SHEET NO. 6.106

RATE SCHEDULE BA-1
BILLING ADJUSTMENTS
(Continued from Page 1)

(1) Fuel Cost Recovery Factor:

The Fuel Cost Recovery Factors applicable to the Fuel Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. These factors are designed to recover the costs of fuel and purchased power (other than capacity payments) incurred by the Company to provide electric service to its customers and are adjusted to reflect changes in these costs from one period to the next. Revisions to the Fuel Cost Recovery Factors within the described period may be determined in the event of a significant change in costs.

(2) Energy Conservation Cost Recovery Factor:

The Energy Conservation Cost Recovery (ECCR) Factor applicable to the Energy Charge under the Company's various rate schedules is normally determined annually by the Florida Public Service Commission for twelve-month periods beginning with the billing month of January. This factor is designed to recover the costs incurred by the Company under its approved Energy Conservation Programs and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the ECCR charge will be included in the monthly max demand only.

(3) Capacity Cost Recovery Factor:

The Capacity Cost Recovery (CCR) Factors applicable to the Energy Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. This factor is designed to recover the cost of capacity payments made by the Company for off-system capacity and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the CCR charge will be included in the monthly max demand only.

(4) Environmental Cost Recovery Clause Factor:

The Environmental Cost Recovery Clause (ECRC) Factors applicable to the Energy Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. This factor is designed to recover environmental compliance costs incurred by the Company and is adjusted to reflect changes in these costs from one period to the next.

(5) Asset Securitization Charge Factor:

The Asset Securitization Charge (ASC) Factors applicable to the Energy Charge under the Company's various rate schedules represent a Nuclear Asset-Recovery Charge approved in a financing order issued to the Company by the Florida Public Service Commission and are adjusted at least semi-annually to ensure timely payment of principal, interest and financing costs of nuclear asset-recovery bonds from the effective date of the ASC until the nuclear asset-recovery bonds have been paid in full or legally discharged and the financing costs have been fully recovered. As approved by the Commission, a Special Purpose Entity (SPE) has been created and is the owner of all rights to the Nuclear Asset-Recovery Charge. The Company shall act as the SPE's collection agent or servicer for the Nuclear Asset-Recovery Charge. The Nuclear Asset-Recovery Charge shall be paid by all existing or future customers receiving transmission or distribution service from the Company or its successors or assignees under Commission-approved rate schedules or under special contracts, even if the customer elects to purchase electricity from alternative electric suppliers following a fundamental change in regulation of public utilities in this state.

(6) Storm Protection Plan Cost Recovery Clause Factor:

The Storm Protection Plan Cost Recovery Clause (SPPCRC) Factors applicable to the Energy Charge under the Company's various rate schedules are normally determined annually by the Florida Public Service Commission for the billing months of January through December. This factor is designed to recover storm protection plan costs incurred by the Company and is adjusted to reflect changes in these costs from one period to the next. For time of use demand rates the SPPCRC charge will be included in the monthly max demand only.

(7) Storm Cost Recovery Surcharge Factor:

In accordance with a Florida Public Service Commission ruling, the Storm Cost Recovery Surcharge (SCRS) factor is applicable to the Energy Charge under the Company's various rate schedules for the billing months of ~~August 2021 through July 2022~~April 2023 through March 2024. This surcharge is designed to recover storm ~~related~~ restoration costs, replenishment of the storm reserve, and interest ~~incurred by the Company~~ related to Hurricanes ~~Eta and Isaias in 2020~~Elsa, Eta, Ian, Isaias, Nicole, and Tropical Storm Fred.

Gross Receipts Tax Factor:

In accordance with Section 203.01(1)(a)1 of the Florida Statutes, a factor of 2.5641% is applicable to electric sales charges for collection of the state Gross Receipts Tax.

Regulatory Assessment Fee Factor:

In accordance with Section 350.113 of the Florida Statutes and Rule 25-6.0131, F.A.C., a factor of 0.072% is applicable to gross operating sales charges for collection of the Regulatory Assessment Fee.

(Continued on Page No. 3)

ISSUED BY: Thomas G. Foster, Vice President, Rates & Regulatory Strategy – FL

EFFECTIVE: ~~January 1, 2023~~April 1, 2023

Item 7

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 23, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (Higgins, Kelley, Zaslow) ALM
Division of Economics (Hampson) JGH
Office of the General Counsel (Brownless, Sandy) JSC

RE: Docket No. 20230001-EI – Fuel and purchased power cost recovery clause with generating performance incentive factor.

AGENDA: 03/07/23 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On January 23, 2023, Florida Power & Light Company (FPL or Company), filed for revision of its currently-effective 2023 fuel cost recovery factors (MCC Petition).[1] FPL's currently-effective 2023 fuel factors were approved last year at the November 17-18, and December 6, 2022 final hearing.[2] Underlying the approval of FPL's 2023 fuel factors was the Florida Public Service Commission's (Commission) review of the Company's projected 2023 fuel- and capacity-related costs. These costs are recovered through fuel and capacity cost recovery factors that are set/reset annually in this docket. However, during the 2022 annual fuel clause cycle, FPL did not include its unrecovered 2022 fuel costs in the fuel factors ultimately approved at the December 6th final hearing. Instead, FPL indicated it would be petitioning for recovery of those costs through a

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[1]Document No. 00354-2023.
[2]Order No. PSC-2023-0026-FOF-EI, issued January 6, 2023, in Docket No. 20230001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.

separate filing. The primary rationale for this course of action was that the extreme volatility of natural gas prices in 2022 made a reliable projection of final 2022 costs impractical. The Commission subsequently ordered FPL's filing to be submitted on or before January 23, 2023.[3]

Mid-Course Corrections

Mid-course corrections are used by the Commission between annual clause hearings whenever costs deviate from revenue by a significant margin. Under Rule 25-6.0424, Florida Administrative Code (F.A.C.), which is commonly referred to as the "mid-course correction rule," a utility must notify the Commission whenever it expects to experience an under- or over-recovery of certain service costs greater than 10 percent. The notification of a 10 percent cost-to-revenue variance shall include a petition for mid-course correction to the fuel cost recovery or capacity cost recovery factors, or shall include an explanation of why a mid-course correction is not practical. The mid-course correction rule and its codified procedures are further discussed throughout this recommendation.

FPL's Petition

FPL's 2022 net under-recovery of fuel costs is approximately $2.13 billion. Through its MCC Petition, FPL is proposing to account for approximately $937 million of its 2022 under-recovery in the current period. For reasons explained later in the recommendation, FPL's proposal will have the effect of reducing its currently-effective 2023 fuel cost recovery factors, while deferring approximately $1.2 billion of the 2022 under-recovery for collection in 2024. The Company is requesting that its revised fuel cost recovery factors and associated tariff become effective beginning with the April 2023 billing cycle. The proposed effective date is further discussed in both Issues 1 and 2.

The Commission is vested with jurisdiction over the subject matter of this proceeding by the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

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[3]Order No. PSC-2023-0026-FOF-EI.

Discussion of Issues

Issue 1: Should the Commission modify FPL's currently-approved fuel cost recovery factors for the purpose of incorporating its actual 2022 under-recovery of fuel costs?

Recommendation: Yes. Staff recommends the Commission approve adjustments to FPL's currently-approved fuel cost recovery factors to incorporate a portion of the Company's actual 2022 under-recovery of fuel costs. Given changes to the Company's estimated 2023 fuel cost, its current 2023 fuel cost recovery factors should be reduced by ($76,815,047). (Higgins, Zaslow, Kelley)

Staff Analysis: FPL participated in the Commission's most-recent fuel hearing which took place during November 17-18, 2022, and December 6, 2022. The fuel order stemming from this proceeding set forth the Company's fuel and capacity cost recovery factors effective with the first billing cycle of January 2023.[4] However, as discussed below, the currently-authorized fuel cost recovery factors do not include certain deferred fuel costs that were incurred in 2022. In support of the deferral, FPL argued that the 2022 natural gas market was so volatile that its total annual fuel (natural gas) cost could not be accurately predicted and that it was better to wait and use actual costs for setting rates with respect to the 2022 under-recovery. Some factors that influenced natural gas prices in 2022 include reduced storage levels, strong liquefied natural gas exports, global military conflict, and capital/expenditure discipline being practiced by drilling companies.

FPL Fuel and Purchased Power Mid-Course Correction

FPL filed for a mid-course correction of its fuel charges on January 23, 2023.[5] The Company's MCC Petition and supporting documentation satisfies the filing requirements of Rule 25-6.0424(1)(b), F.A.C. In accordance with the noticing requirement of Rule 25-6.0424(2), F.A.C., FPL filed a letter on April 15, 2022, informing the Commission that it was projecting an under-recovery position of greater than 10 percent for the recovery period ending on December 31, 2022.[6] However, in analyzing settlement prices for natural gas, the Company determined that the continuing price volatility warranted deferring a decision to file for a mid-course correction.

The exact factors proposed in this proceeding are currently contemplated to be charged for 9 months. As is typical procedure, later this year newly developed 12-month-applicable factors will be proposed for authorization to begin with the first billing cycle of January 2024.

Actual Period-Ending 2022 Fuel Cost Recovery Position

FPL's net fuel cost recovery position at the end of 2022 is an under-recovery of $2,128,114,614.[7] This amount includes FPL's final 2021 true-up of $10,256,384.[8]

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[4]Order No. PSC-2023-0026-FOF-EI.
[5]Document No. 00354-2023.
[6]Document No. 02477-2022.
[7]Document No. 00354-2023.
[8]Order No. PSC-2023-0026-FOF-EI.

Increased pricing for natural gas was the primary driver of the 2022 under-recovery identified above. More specifically, the Company estimated an annual natural gas cost of $5.81 per million British thermal unit (MMBtu) in its last mid-course correction filing and derivation of customer fuel rates.[9] This figure includes delivery costs. However, as indicated in the Company's December 2022 A-Schedule, FPL's average 2022 cost of natural gas was $8.74 per MMBtu, representing a difference of 50.4 percent.[10] Natural gas-fired generation comprised approximately 72.3 percent of FPL's generation mix in 2022.[11]

Projected 2023 Fuel Cost Recovery Position

FPL's 2023 fuel-related revenue requirement has decreased substantially since the filing of its last cost projection in September 2022.[12] More specifically, the results of this updated estimate are a reduction in FPL's estimated 2023 fuel-related costs in the amount of ($1,013,845,409). The amount of the 2022 under-recovery proposed for collection through new 2023 rates is $937,030,362. Thus, the proposed net or decremental amount for inclusion into 2023 rates is ($76,815,047).[13]

The primary factor driving the change in projected 2023 fuel costs is lower assumed pricing for natural gas. More specifically, the underlying market-based natural gas price data used for the 2023 fuel cost projection was sourced on July 18, 2022.[14] This underlying data was used to produce an estimated average 2023 delivered natural gas cost of $7.42 per MMBtu.[15] However, as noted above and indicated in its MCC Petition, FPL now estimates its average cost of natural gas in 2023 will be $5.70 per MMBtu, representing a decrease of 23.2 percent.[16] The updated cost estimate was based on natural gas futures/prices sourced on January 3, 2023, or roughly six months later than the previous estimate used to set current rates.[17]

Recovery Period and Interest Premium

As proposed, FPL's recovery period for its 2022 under-recovery is over 21 months (beginning April 2023 and ending December 2024).[18] FPL utilized the 30-day AA Financial Commercial Paper Rate published by the Commission to determine its 2022 interest amount.[19] The projected 2023 monthly interest rate was assumed for all months by using the 30-day AA Financial Commercial Paper Rate published on the first business day of January 2023 of 0.364 percent.[20]

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[9]Document No. 12592-2021.
[10]Document No. 00341-2023.
[11]*Id*.
[12]Document No. 05977-2022.
[13]Document No. 00354-2023.
[14]*Id*.
[15]*Id*.
[16]Document No. 00354-2023.
[17]*Id*.
[18]*Id*.
[19]Document No. 01065-2023.
[20]Document No. 00878-2023 and The Federal Reserve System (U.S. Federal Reserve) published Commercial Paper Rates which can be located via the following link: https://www.federalreserve.gov/releases/cp/

Mid-Course Correction Percentage

Following the methodology prescribed in Rule 25-6.0424(1)(a), F.A.C., the mid-course percentage is equal to the estimated end-of-period total net true-up, including interest, divided by the current period's total actual and estimated jurisdictional fuel revenue applicable to period, or ($1,124,525,589) / $4,849,117,525.[21] This calculation results in a mid-course correction level of (23.2) percent at December 31, 2023.

Fuel Factor

FPL's currently-approved annual levelized fuel factor beginning with the first January 2023 billing cycle is 4.036 cents per kilowatt-hour (kWh).[22] The Company is requesting to decrease its currently-approved 2023 annual levelized fuel factor beginning April 2023 to 3.957 cents per kWh, or by (2.0) percent.[23]

Bill Impacts

In Tables 1-1 and 1-2 below, the bill impacts of the MCC to typical residential customers using 1,000 kWh of electricity a month in FPL's Peninsular service territory and FPL's Northwest (former Gulf Power Company) service territory are shown. These tables also include the storm-related cost recovery proposals that, if approved, would begin in April 2023.[24] Additional information related to storm restoration is provided following Table 1-2. Further below Tables 1-1 and 1-2, staff discusses the impacts of the MCC on non-residential customers:

[21]Document No. 00354-2023, Schedule E1-B.
[22]Order No. PSC-2023-0026-FOF-EI.
[23]Document No. 00354-2023.
[24]Document No. 00358-2023.

Table 1-1
FPL Peninsular Service Territory
Monthly Residential Billing Detail for the First 1,000 kWh - Primary Storm Cost Recovery

Invoice Component	Currently-Approved Charges March 2023 ($)	Proposed Charges Beginning April 2023 ($)	Difference ($)	Difference (%)
Base Charge	$80.11	$80.11	$0.00	0.0%
Fuel Charge	37.45	36.56	(0.89)	(2.4%)
Conservation Charge	1.22	1.22	0.00	0.0%
Capacity Charge	2.12	2.12	0.00	0.0%
Environmental Charge	3.12	3.12	0.00	0.0%
Storm Protection Plan Charge	3.82	3.82	0.00	0.0%
Storm Restoration Surcharge[25]	0.00	13.84	13.84	100.0%
Transition Rider	(1.58)	(1.58)	0.00	0.0%
Gross Receipts Tax	3.33	3.67	0.34	10.2%
Total	$129.59	$142.88	$13.29	10.3%

Source: Document No. 00878-2023 and staff calculations.

Bill Impacts - FPL Peninsular Service Territory

FPL's currently-approved total residential charge for the first 1,000 kWh of usage for March 2023 is $129.59.[26] If the Company's mid-course correction and primary storm cost recovery proposals are approved, then the current total residential charge for the first 1,000 kWh of usage beginning in April will be $142.88, an increase of approximately 10.3 percent. For non-residential customers, FPL reported that bill increases based on average levels of usage for small-sized commercial customers would range from approximately 5.0 to 9.3 percent, 5.0 percent for medium-size commercial customers, 4.0 percent for large-size commercial customers, and (0.8) percent for industrial customers.[27]

[25]Subject to Commission approval in Docket No. 20230017-EI.
[26]Document No. 00878-2023.
[27]Document No. 01065-2023.

Table 1-2
FPL Northwest Service Territory
Monthly Residential Billing Detail for the First 1,000 kWh - Primary Storm Cost Recovery

Invoice Component	Currently-Approved Charges March 2023 ($)	Proposed Charges Beginning April 2023 ($)	Difference ($)	Difference (%)
Base Charge	$80.11	$80.11	$0.00	0.0%
Fuel Charge	37.45	36.56	(0.89)	(2.4%)
Conservation Charge	1.22	1.22	0.00	0.0%
Capacity Charge	2.12	2.12	0.00	0.0%
Environmental Charge	3.12	3.12	0.00	0.0%
Storm Protection Plan Charge	3.82	3.82	0.00	0.0%
Storm Restoration Surcharge[28]	11.00	24.84	13.84	125.8%
Transition Rider	16.85	16.85	0.00	0.0%
Gross Receipts Tax	4.12	4.45	0.33	8.0%
Total	$159.81	$173.09	$13.28	8.3%

Source: Document No. 00878-2023 and staff calculations.

Bill Impacts - FPL Northwest Service Territory

FPL's currently-approved Northwest total residential charge for the first 1,000 kWh of usage for March 2023 is $159.81.[29] If the Company's mid-course correction and primary storm cost recovery proposals are approved, the current total Northwest residential charge for the first 1,000 kWh of usage beginning in April will be $173.09, an increase of 8.3 percent. For non-residential customers, FPL reported that bill increases based on average levels of usage for small-sized commercial customers would range from approximately 4.2 to 7.4 percent, and 4.2 percent for medium-size commercial customers, and 3.4 percent for large-size commercial customers. A figure associated with an industrial class for the Northwest service territory was not identified.[30]

Alternative Storm Restoration Cost Proposal

As noted earlier, also shown in Tables 1-1 and 1-2 above are the Company's "Primary" proposed rate adjustments related to its recovery of storm restoration costs with respect to Hurricanes Ian and Nicole, as well as replenishment of the storm reserve (Storm Restoration Recovery Charge). In Docket No. 20230017-EI, the Company discussed an alternative storm cost recovery method. FPL has requested recovery of these storm-related costs in Docket No. 20230017-EI.[31] However, while the corresponding rate adjustments are shown here, the Storm Restoration Recovery Charge, associated rates, or potential rate structures are not at issue in this proceeding.

[28]Subject to Commission approval in Docket No. 20230017-EI.
[29]Document No. 00878-2023.
[30]Document No. 01065-2023.
[31]See Document No. 00358-2023 for further information regarding FPL's Interim Storm Charge request.

For comparative purposes, Tables 1-3 and 1-4, display the bill impacts of the MCC as well as the alternative storm cost recovery proposal on typical residential customers using 1,000 kWh of electricity a month in FPL's Peninsular and Northwest service territories:

Table 1-3
FPL Peninsular Service Territory
Monthly Residential Billing Detail for the First 1,000 kWh - Alternate Storm Cost Recovery

Invoice Component	Currently-Approved Charges March 2023 ($)	Alternate Charges Beginning April 2023 ($)	Difference ($)	Difference (%)
Base Charge	$80.11	$80.11	$0.00	0.0%
Fuel Charge	37.45	36.56	(0.89)	(2.4%)
Conservation Charge	1.22	1.22	0.00	0.0%
Capacity Charge	2.12	2.12	0.00	0.0%
Environmental Charge	3.12	3.12	0.00	0.0%
Storm Protection Plan Charge	3.82	3.82	0.00	0.0%
Storm Restoration Surcharge	0.00	15.30	15.30	100.0%
Transition Rider	(1.58)	(1.58)	0.00	0.0%
Gross Receipts Tax	3.33	3.71	0.38	11.4%
Total	$129.59	$144.38	$14.79	11.4%

Source: Document No. 00878-2023 and staff calculations.

Table 1-4
FPL Northwest Service Territory
Monthly Residential Billing Detail for the First 1,000 kWh - Alternate Storm Cost Recovery

Invoice Component	Currently-Approved Charges March 2023 ($)	Alternate Charges Beginning April 2023 ($)	Difference ($)	Difference (%)
Base Charge	$80.11	$80.11	$0.00	0.0%
Fuel Charge	37.45	36.56	(0.89)	(2.4%)
Conservation Charge	1.22	1.22	0.00	0.0%
Capacity Charge	2.12	2.12	0.00	0.0%
Environmental Charge	3.12	3.12	0.00	0.0%
Storm Protection Plan Charge	3.82	3.82	0.00	0.0%
Storm Restoration Surcharge	11.00	15.30	4.30	39.1%
Transition Rider	16.85	16.85	0.00	0.0%
Gross Receipts Tax	4.12	4.20	0.08	1.9%
Total	$159.81	$163.30	$3.49	2.2%

Source: Document No. 00878-2023 and staff calculations.

Summary
FPL's MCC Petition indicates a need for its fuel cost recovery factors to be revised. As indicated in the petition, the Company's underlying 2023 fuel-related revenue requirement has been reduced by ($1,013,845,409). Further, the Company proposes to incorporate $937,030,362 of its 2022 fuel cost under-recovery into the current period. Thus, FPL's current fuel cost recovery factors should be reduced by ($76,815,047). The revised fuel cost recovery factors associated with staff's recommendation are shown on Appendix A.

Conclusion
Staff recommends that the Commission approve adjustments to FPL's currently-approved fuel cost recovery factors to incorporate a portion of the Company's actual 2022 under-recovery of fuel costs. Given changes to the Company's estimated 2023 fuel cost, its current 2023 fuel cost recovery factors should be reduced by ($76,815,047).

Issue 2: If approved by the Commission, what is the appropriate effective date for FPL's revised fuel cost recovery factors?

Recommendation: The fuel cost recovery factors, as shown on Appendix A, should become effective with the first billing cycle of April 2023. (Hampson, Brownless, Sandy)

Staff Analysis: Over the last 20 years in the Fuel Clause docket, the Commission has considered the effective date of rates and charges of revised fuel cost recovery factors on a case-by-case basis. The Commission has approved fuel cost recovery factor rate decreases effective sooner than the next full billing cycle after the date of the Commission's vote with the range between the vote and the effective date being from 25 to 2 days. The rationale for that action being that it was in the customers' best interests to implement the lower rate as soon as possible.[32]

With regard to fuel cost recovery factor rate increases, the Commission has approved an effective date of the revised factors ranging from 14 to 29 days after the vote.[33] The Commission noted that typically the utility had given its customers 30 days' written notice before the date of the vote that a fuel cost recovery factor increase had been requested and provided the proposed effective date of the higher fuel factors.

In its MCC Petition, FPL proposes to collect the actual 2022 under-recovery of fuel costs over 21 months, beginning with the first billing cycle of April 2023. In the instant case, there are 27 days between the Commission's vote on March 7th and the beginning of FPL's April 2023 billing cycle (April 3rd).[34]

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[32]Order No. PSC-08-0825-PCO-EI, issued December 22, 2008, in Docket No. 080001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-09-0254-PCO-EI, issued April 27, 2009, in Docket No. 090001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor;* Order No. PSC-11-0581-PCO-EI, issued on December 19, 2011, in Docket No. 110001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-12-0342-PCO-EI, issued July 2, 2012, in Docket No. 120001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-2012-0082-PCO-EI, issued February 24, 2012, in Docket No. 120001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-15-0161-PCO-EI, issued April 30, 2015, in Docket No. 150001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-2018-0313-PCO-EI, issued June 18, 2018, in Docket No. 20180001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order PSC-2020-0154-PCO-EI, issued May 14, 2020, in Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

[33]Order No. PSC-03-0381-PCO-EI, issued March 19, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-03-0382-PCO-EI, issued March 19, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-03-0400, issued March 24, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-03-0849-PCO-EI, issued July 22, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-09-0213-PCO-EI, issued April 9, 2009, in Docket No. 090001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor;* Order No. PSC-2019-0109-PCO-EI, issued March 22, 2019, in Docket No. 20190001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

[34]Document No. 00878-2023.

Concerning advisement of the instant request, the Company has engaged in numerous outreach efforts regarding the potential bill impacts of this proceeding. Specifically, FPL issued a press release on January 23, 2023 informing its customers of the MCC proposal. Further, in both September and December of 2022, the Company informed its customers through a billing information portal titled "2023 Bills" of the future potential adjustments related to the under-recovery of 2022 fuel costs. The Company has also planned to issue notices with its bills beginning February 8th, 2023, regarding the pending rate request. The Company also separately contacted numerous commercial, industrial, and governmental customers to inform them of its proposal and the potential impact on their bills.[35]

Conclusion

Staff recommends that the fuel cost recovery factors, as shown on Appendix A, become effective with the first billing cycle of April 2023.

[35] Document No. 00878-2023.

Issue 3: Should this docket be closed?

Recommendation: No. The 20230001-EI docket is an on-going proceeding and should remain open. (Brownless, Sandy)

Staff Analysis: The fuel docket is an on-going proceeding and should remain open.

~~Sixty-First~~Sixty-Second Revised Sheet No.8.030
Cancels Sixty-First~~Sixtieth~~ Revised Sheet No.8.030

FLORIDA POWER & LIGHT COMPANY

BILLING ADJUSTMENTS

The following charges are applied to the Monthly Rate of each rate schedule as indicated and are calculated in accordance with the formula specified by the Florida Public Service Commission.

RATE	FUEL			CONSERVATION		CAPACITY		ENVIRON-MENTAL	STORM PROTECTION	
SCHEDULE	¢/kWh	¢/kWh	¢/kWh	¢/kWh	$/kW	¢/kWh	$/kW	¢/kWh	¢/kWh	$/kW
	Levelized	On-Peak	Off-Peak							
RS-1, RS-1 w/RTR-1 1st 1,000 kWh	~~3.745~~3.656			0.122		0.212		0.312	0.382	
RS-1, RS-1 w/ RTR-1 all addn kWh	~~4.745~~4.656			0.122		0.212		0.312	0.382	
RS-1 w/RTR-1 All kWh		~~0.320~~0.286	(~~0.137~~0.123)	0.122		0.212		0.312	0.382	
GS-1	~~4.047~~3.968			0.125		0.220		0.323	0.346	
GST-1		~~4.367~~4.254	~~3.910~~3.845	0.125		0.220		0.323	0.346	
GSD-1, GSD1-EV, GSD-1 w/SDTR (Jan – May)(Oct – Dec)	~~4.047~~3.968				0.43		0.72	0.279		0.70
GSD-1 w/SDTR (Jun-Sept)		~~5.383~~4.880	~~3.877~~3.853		0.43		0.72	0.279		0.70
GSDT-1, HLFT-1 GSDT-1w/SDTR (Jan – May)(Oct – Dec)		~~4.367~~4.254	~~3.910~~3.845		0.43		0.72	0.279		0.70
GSDT-1 w/SDTR (Jun-Sept)		~~5.383~~4.880	~~3.877~~3.853		0.43		0.72	0.279		0.70
GSLD-1, CS-1, GSLD1-EV GSLD-1w/SDTR (Jan – May)(Oct – Dec)	~~4.043~~3.964				0.47		0.80	0.281		0.73
GSLD-1 w/SDTR (Jun-Sept)		~~5.377~~4.875	~~3.873~~3.848		0.47		0.80	0.281		0.73
GSLDT-1, CST-1, HLFT-2, GSLDT-1 w/SDTR (Jan–May & Oct–Dec)		~~4.362~~4.249	~~3.906~~3.840		0.47		0.80	0.281		0.73
GSLDT-1 w/SDTR (Jun-Sept)		~~5.377~~4.875	~~3.873~~3.848		0.47		0.80	0.281		0.73
GSLD-2, CS-2, GSLD-2 w/SDTR (Jan – May)(Oct – Dec)	~~4.012~~3.933				0.49		0.80	0.244		0.66
GSLD-2 w/SDTR (Jun-Sept)		~~5.337~~4.839	~~3.844~~3.820		0.49		0.80	0.244		0.66
GSLDT-2, CST-2, HLFT-3, GSLDT-2 w/SDTR (Jan – May)(Oct – Dec)		~~4.330~~4.217	~~3.876~~3.812		0.49		0.80	0.244		0.66
GSLDT-2 w/SDTR (Jun-Sept)		~~5.337~~4.839	~~3.844~~3.820		0.49		0.80	0.244		0.66
GSLD-3, CS-3	~~3.924~~3.848				0.45		0.73	0.226		0.10
GSLDT-3, CST-3		~~4.235~~4.125	~~3.791~~3.728		0.45		0.73	0.226		0.10

(Continued on Sheet No. 8.030.1)

Issued by: Tiffany Cohen, Executive Director, Rate Development & Strategy
Effective: ~~February 1, 2023~~

~~Thirty-Seventh~~Thirty-Eighth Revised Sheet No.8.030.1
Cancels Thirty-Seventh ~~Thirty-Sixth~~ Revised Sheet No.8.030.1

FLORIDA POWER & LIGHT COMPANY

(Continued from Sheet No. 8.030)

BILLING ADJUSTMENTS (Continued)

RATE	FUEL			CONSERVATION			CAPACITY			ENVIRON-MENTAL	STORM PROTECTION		
SCHEDULE	¢/kWh	¢/kWh	¢/kWh	¢/kWh	$/kW	$/kW	¢/kWh	$/kW	$/kW	¢/kWh	¢/kWh	$/kW	$/kW
	Levelized	On-Peak	Off-Peak										
OS-2	~~4.012~~3.933			0.085			0.127			0.211	0.815		
MET	~~4.012~~3.933				0.42			0.69		0.258		0.74	
CILC-1(G)		~~4.367~~4.254	~~3.910~~3.845		0.51			0.81		0.234		0.68	
CILC-1(D)		~~4.331~~4.219	~~3.877~~3.813		0.51			0.81		0.234		0.68	
CILC-1(T)		~~4.235~~4.125	~~3.791~~3.728		0.51			0.79		0.208		0.11	
SL-1,OL-1, RL-1, PL- 1/SL-1M, LT-1,OS I/II	~~3.983~~3.911			0.038			0.016			0.044	0.288		
SL-2, GSCU-1/SL- 2M	~~4.047~~3.968			0.090			0.137			0.207	0.316		
					RDC	DDC		RDC	DDC			RDC	DDC
SST-1(T)		~~4.235~~4.125	~~3.791~~3.728		0.05	0.03		0.09	0.04	0.292		0.01	0.01
SST-1(D1)		~~4.367~~4.254	~~3.910~~3.845		0.05	0.03		0.09	0.04	0.565		0.12	0.05
SST-1(D2)		~~4.362~~4.249	~~3.906~~3.840		0.05	0.03		0.09	0.04	0.565		0.12	0.05
SST-1(D3)		~~4.330~~4.217	~~3.876~~3.812		0.05	0.03		0.09	0.04	0.565		0.12	0.05
ISST-1(D)		~~4.331~~4.219	~~3.877~~3.813		0.05	0.03		0.09	0.04	0.565		0.12	0.05
ISST-1(T)		~~4.235~~4.125	~~3.791~~3.728		0.05	0.03		0.09	0.04	0.292		0.01	0.01

(Continued on Sheet No. 8.030.2)

Issued by: Tiffany Cohen, Executive Director, Rate Development & Strategy
Effective: ~~February 1, 2023~~

Item 8

FILED 2/23/2023
DOCUMENT NO. 01239-2023
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 23, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Accounting and Finance (Higgins, Kelley, Zaslow) ALM
Division of Economics (Hampson) JGH
Office of the General Counsel (Brownless, Sandy) JSC

RE: Docket No. 20230001-EI – Fuel and purchased power cost recovery clause with generating performance incentive factor.

AGENDA: 03/07/23 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On January 23, 2023, Tampa Electric Company (TECO or Company), filed for revision of its currently-effective 2023 fuel cost recovery factors.[1] The Company subsequently filed an amended petition on February 8, 2023 (MCC Petition).[2] TECO's currently-effective 2023 fuel factors were approved last year at the November 17-18, and December 6, 2022 final hearing.[3] Underlying the approval of TECO's 2023 factors was the Florida Public Service Commission's (Commission) review of the Company's projected 2023 fuel- and capacity-related costs. These costs are recovered through fuel and capacity cost recovery factors that are set/reset annually in this docket. However, during the 2022 annual fuel clause cycle, TECO proposed not to include

[1]Document No. 00380-2023.
[2]Document No. 01008-2023.
[3]Order No. PSC-2023-0026-FOF-EI, issued January 6, 2023, in Docket No. 20230001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.

its unrecovered 2022 fuel costs in the fuel factors approved at the December 6th final hearing. Instead, TECO indicated it would be petitioning for recovery of those costs through a separate filing. The primary rationale for this course of action is that the extreme volatility of the natural gas prices in 2022 made a reliable projection of final 2022 costs impractical. The Commission subsequently ordered TECO's filing to be submitted on or before January 23, 2023.[4]

Mid-Course Corrections

Mid-course corrections are used by the Commission between annual clause hearings whenever costs deviate from revenue by a significant margin. Under Rule 25-6.0424, Florida Administrative Code (F.A.C.), which is commonly referred to as the "mid-course correction rule," a utility must notify the Commission whenever it expects to experience an under- or over-recovery of certain service costs greater than 10 percent. The notification of a 10 percent cost-to-revenue variance shall include a petition for mid-course correction to the fuel cost recovery or capacity cost recovery factors, or shall include an explanation of why a mid-course correction is not practical. The mid-course correction rule and its codified procedures are further discussed throughout this recommendation.

TECO's MCC Petition

TECO's net 2022 under-recovery of fuel cost is approximately $518 million. Through its MCC Petition, TECO is proposing to both increase its currently-effective 2023 cost recovery factors by approximately $65 million, and defer approximately $296 million for recovery in 2024. The Company also incorporated 2023 cost reductions into its proposal that are further discussed in Issue 1. TECO is requesting that its revised fuel factors and associated tariff become effective beginning with the first billing cycle for April 2023. The proposed effective date is further discussed in both Issues 1 and 2.

The Commission is vested with jurisdiction over the subject matter of this proceeding by the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

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[4]Order No. PSC-2023-0026-FOF-EI.

Discussion of Issues

Issue 1: Should the Commission modify TECO's currently-approved fuel cost recovery factors for the purpose of incorporating its actual 2022 under-recovery of fuel costs?

Recommendation: Yes. Staff recommends the Commission approve adjustments to TECO's currently-approved fuel cost recovery factors to incorporate a portion of the Company's actual 2022 under-recovery of fuel costs in the amount of $64,989,253. (Higgins, Zaslow, Kelley)

Staff Analysis: TECO participated in the Commission's most-recent fuel hearing which took place during November 17-18, 2022, and December 6, 2022, in this docket. The fuel order stemming from this proceeding set forth the Company's fuel and capacity cost recovery factors effective with the first billing cycle of January 2023.[5] However, as discussed below, the currently-authorized fuel cost recovery factors do not include certain fuel costs that were incurred in 2022. In support of the deferral, TECO argued that the 2022 natural gas market was so volatile that its total annual fuel (natural gas) cost could not be accurately predicted and that it was better to wait and use actual costs for setting rates with respect to the 2022 under-recovery. Some factors that influenced natural gas prices in 2022 include reduced storage levels, strong liquefied natural gas exports, global military conflict, and capital/expenditure discipline being practiced by drilling companies.

TECO Fuel and Purchased Power Mid-Course Correction

TECO initially filed for a mid-course correction of its fuel charges on January 23, 2023.[6] This filing was amended on February 8, 2023.[7] The Company's MCC petition and supporting documentation satisfies the filing requirements of Rule 25-6.0424(1)(b), F.A.C. In accordance with the noticing requirement of Rule 25-6.0424(2), F.A.C., TECO filed a letter on April 21, 2022, informing the Commission that it was projecting an under-recovery position of greater than 10 percent for the period ending on December 31, 2022.[8] However, in analyzing settlement prices for natural gas, the Company determined that the continuing price volatility warranted deferring a decision to file for a mid-course correction.

The exact factors proposed in this proceeding are currently contemplated to be charged for 9 months. As is typical procedure, later this year newly developed 12-month-applicable factors will be proposed for implementation beginning with the first billing cycle of January 2024.

Actual Period-Ending 2022 Fuel Cost Recovery Position

TECO's net fuel cost recovery position at the end of 2022 is an under-recovery of $517,989,768.[9] TECO recovered its final 2021 true-up amount through a prior mid-course correction.[10]

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[5]Order No. PSC-2023-0026-FOF-EI.
[6]Document No. 00380-2023.
[7]Document No. 01008-2023.
[8]Document No. 02571-2022.
[9]Document No. 01008-2023.
[10]Order No. PSC-2023-0026-FOF-EI.

Increased pricing for natural gas was the primary driver of the 2022 under-recovery identified above. More specifically, the Company estimated an annual natural gas cost of $4.98 per million British thermal unit (MMBtu) in its last mid-course correction filing and derivation of customer fuel rates.[11] This figure includes delivery costs. However, as indicated in the Company's December 2022 A-Schedule, TECO's average 2022 cost of natural gas was $8.32 per MMBtu, representing a difference of 67.1 percent.[12] Natural gas-fired generation comprised approximately 85.8 percent of TECO's generation mix in 2022.[13]

Projected 2023 Fuel Cost Recovery Position

TECO's 2023 fuel-related revenue requirement decreased substantially since the filing of its last cost projection in September 2022.[14] More specifically, the results of this updated estimate is a reduction in TECO's estimated 2023 fuel-related costs in the amount of ($171,157,078).[15] After accounting for carrying charges on the true-up balance, the net cost difference is ($157,006,362). The amount of the 2022 under-recovery proposed for collection in 2023 is $221,995,615. Thus, the proposed incremental amount for inclusion into 2023 rates is $64,989,253.

The primary factor driving the change in projected 2023 fuel costs is lower assumed pricing for natural gas. More specifically, the underlying market-based natural gas price data used for the 2023 fuel cost projection was sourced on (5-day average ending) August 1, 2022.[16] This underlying data was used to produce an estimated average 2023 delivered natural gas cost of $7.49 per MMBtu.[17] However, TECO now estimates its average cost of natural gas in 2023 will be $5.92 per MMBtu, representing a decrease of 21.0 percent.[18] The updated cost estimate was based on natural gas futures/prices sourced on (5-day average ending) December 30, 2022, or roughly five months from the previous estimate that was used to set current rates.[19]

Recovery Period and Interest Premium

As proposed, TECO's recovery period for its 2022 under-recovery of fuel costs is over 21 months (beginning April 2023 and ending December 2024).[20] TECO utilized the 30-day AA Financial Commercial Paper Rate to determine its 2022 interest amount.[21] The projected 2023 interest rate was assumed to be the forecasted Federal Funds Rate sourced via a third party, namely "Refinitiv," of 0.263 percent (2023 monthly average). [22]

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[11]Document No. 00350-2022.
[12]Document No. 00488-2023.
[13]*Id*.
[14]Document No. 05966-2022.
[15]Document No. 01008-2023.
[16]Document No. 00877-2023.
[17]Document No. 05966-2022.
[18]Document No. 01008-2023.
[19]Document No. 00877-2023.
[20]Document No. 00380-2023.
[21]Document No. 00877-2023, and The Federal Reserve System (U.S. Federal Reserve) published Commercial Paper Rates which can be located via the following link: https://www.federalreserve.gov/releases/cp/
[22]Document No. 00877-2023.

Mid-Course Correction Percentage

Following the methodology prescribed in Rule 25-6.0424(1)(a), F.A.C., the mid-course percentage is equal to the estimated end-of-period total net true-up, including interest, divided by the current period's total actual and estimated jurisdictional fuel revenue applicable to period, or ($360,983,406) / $955,861,787.[23] This calculation results in a mid-course correction level of (37.8) percent at December 31, 2023.

Fuel Factor

TECO's currently-approved annual levelized fuel factor beginning with the first January 2023 billing cycle is 4.825 cents per kilowatt-hour (kWh).[24] The Company is requesting to increase its currently-approved 2023 annual levelized fuel factor (beginning April 2023) to 5.239 cents per kWh, or by 8.6 percent.[25]

Bill Impacts

Table 1-1 displays the bill impacts of the MCC on typical residential customers using 1,000 kWh of electricity a month. This table also includes TECO's storm-related cost recovery proposal that, if approved, would begin in April 2023.[26] Additional information related to storm restoration is provided following Table 1-1, as well as a discussion regarding the impacts of the MCC on non-residential customers.

[23]Document No. 01008-2023, Schedule E2.
[24]Order No. PSC-2023-0026-FOF-EI.
[25]Document No. 01008-2023.
[26]See Document No. 00379-2023 for further information regarding TECO's Interim Storm Charge request.

Table 1-1
Tampa Electric Company
Monthly Residential Billing Detail for the First 1,000 kWh

Invoice Component	Currently-Approved Charges March 2023 ($)	Proposed Charges Beginning April 2023 ($)	Difference ($)	Difference (%)
Base Charge	$86.22	$86.22	$0.00	0.0%
Fuel Charge	45.25	49.08	3.83	8.5%
Capacity Charge	(0.18)	(0.18)	0.00	0.0%
Conservation Charge	2.81	2.81	0.00	0.0%
Environmental Charge	0.92	0.92	0.00	0.0%
Storm Protection Plan Charge	3.73	3.73	0.00	0.0%
Clean Energy Transition Mechanism	4.30	4.30	0.00	0.0%
Storm Restoration Charge[27]	0.00	10.22	10.22	100.0%
Gross Receipts Tax	3.67	4.03	0.36	9.8%
Total	$146.72	$161.13	$14.41	9.8%

Source: TECO MCC Petition, Schedule E-10.

The storm restoration costs are with respect to Hurricanes: Dorian, Elsa, Ian, and Nicole, and Tropical Storms: Alberto, Eta, and Nestor, as well as certain storm-related software and storm reserve replenishment costs. TECO has requested recovery of these costs in Docket No. 20230019-EI. Therefore, while the proposed residential rate adjustment is shown here, neither the Interim Storm Charge nor those associated rates are at issue in this proceeding.

TECO's currently-approved total residential charge for the first 1,000 kWh of usage for March 2023 is $146.72.[28] If the Company's mid-course correction and storm cost recovery proposal are approved, the current total residential charge for the first 1,000 kWh of usage beginning in April will be $161.13, an increase of 9.8 percent. For non-residential rate classes, TECO reported that bill increases based on average levels of usage for General Service customers would range from approximately 9.2 to 10.4 percent, and for General Service Demand customers, increases would range from approximately 6.3 to 7.0 percent.[29]

Summary

TECO's MCC Petition indicates a need for its fuel cost recovery factors to be revised. Thus, TECO's fuel cost recovery factors should be adjusted by $64,989,253 to incorporate a portion of

[27]Subject to Commission approval in Docket No. 20230019-EI.
[28]Document No. 01008-2023.
[29]Document No. 01060-2023.

its actual 2022 end-of-year fuel cost under-recovery. The revised fuel cost recovery factors associated with staff's recommendation are shown on Appendix A.

Conclusion

Staff recommends that the Commission approve adjustments to TECO's currently-approved fuel cost recovery factors to incorporate a portion of the Company's actual 2022 under-recovery of fuel costs in the amount of $64,989,253.

Issue 2: If approved by the Commission, what is the appropriate effective date for TECO's revised fuel cost recovery factors?

Recommendation: The fuel cost recovery factors, as shown on Appendix A, should become effective with the first billing cycle of April 2023. (Hampson, Brownless, Sandy)

Staff Analysis: Over the last 20 years in the Fuel Clause docket, the Commission has considered the effective date of rates and charges of revised fuel cost recovery factors on a case-by-case basis. The Commission has approved fuel cost recovery factor rate decreases effective sooner than the next full billing cycle after the date of the Commission's vote with the range between the vote and the effective date being from 25 to 2 days. The rationale for that action being that it was in the customers' best interests to implement the lower rate as soon as possible.[30]

With regard to fuel cost recovery factor rate increases, the Commission has approved an effective date of the revised factors ranging from 14 to 29 days after the vote.[31] The Commission noted that typically the utility had given its customers 30 days' written notice before the date of the vote that a fuel cost recovery factor increase had been requested and provided the proposed effective date of the higher fuel factors.

In its MCC Petition, TECO proposes to collect the actual 2022 under-recovery of fuel costs over 21 months, beginning with the first billing cycle of April 2023. In the instant case, there are 27 days between the Commission's vote on March 7th and the beginning of TECO's April 2023 billing cycle (April 3rd).[32]

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[30]Order No. PSC-08-0825-PCO-EI, issued December 22, 2008, in Docket No. 080001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-09-0254-PCO-EI, issued April 27, 2009, in Docket No. 090001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor;* Order No. PSC-11-0581-PCO-EI, issued on December 19, 2011, in Docket No. 110001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-12-0342-PCO-EI, issued July 2, 2012, in Docket No. 120001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-2012-0082-PCO-EI, issued February 24, 2012, in Docket No. 120001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-15-0161-PCO-EI, issued April 30, 2015, in Docket No. 150001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-2018-0313-PCO-EI, issued June 18, 2018, in Docket No. 20180001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order PSC-2020-0154-PCO-EI, issued May 14, 2020, in Docket No. 20200001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

[31]Order No. PSC-03-0381-PCO-EI, issued March 19, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-03-0382-PCO-EI, issued March 19, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-03-0400, issued March 24, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-03-0849-PCO-EI, issued July 22, 2003, in Docket No. 030001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*; Order No. PSC-09-0213-PCO-EI, issued April 9, 2009, in Docket No. 090001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor;* Order No. PSC-2019-0109-PCO-EI, issued March 22, 2019, in Docket No. 20190001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.*

[32]Document No. 00877-2023.

Concerning advisement of the instant request, the Company issued a press release on January 23, 2023 informing its customers of the MCC proposal. Further, TECO will begin including a notice on customer bills starting in March. The bill notice will inform TECO's customers of the proposed rate increase. The Company also plans to post similar information to its website. The Company also separately contacted numerous high-usage customers to inform them of its proposal and the potential impact on their bills.[33]

Conclusion

Staff recommends that the fuel cost recovery factors, as shown on Appendix A, become effective with the first billing cycle of April 2023.

[33]Document No. 00877-2023.

Issue 3: Should this docket be closed?

Recommendation: No. The 20230001-EI docket is an on-going proceeding and should remain open. (Brownless, Sandy)

Staff Analysis: The fuel docket is an on-going proceeding and should remain open.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

EIGHTY-~~FIFTH~~ SIXTH REVISED SHEET NO. 6.020
CANCELS EIGHTY-~~FOURTH~~ FIFTH REVISED SHEET NO. 6.020

ADDITIONAL BILLING CHARGES

TOTAL FUEL AND PURCHASED POWER COST RECOVERY CLAUSE: The total fuel and purchased power cost recovery factor shall be applied to each kilowatt-hour delivered, and shall be computed in accordance with the formula prescribed by the Florida Public Service Commission. The following fuel recovery factors by rate schedule have been approved by the Commission:

RECOVERY PERIOD
(April~~January~~ 2023 through December 2023)

Rate Schedules		¢/kWh Fuel Standard	¢/kWh Fuel Peak	¢/kWh Fuel Off-Peak	¢/kWh Capacity	¢/kWh Environmental
RS (up to 1,000 kWh)		4.908~~525~~			-0.018	0.092
RS (over 1,000 kWh)		5.908~~525~~			-0.018	0.092
RSVP-1	(P_1)	5.239~~4.832~~			-0.018	0.092
	(P_2)	5.239~~4.832~~			-0.018	0.092
	(P_3)	5.239~~4.832~~			-0.018	0.092
	(P_4)	5.239~~4.832~~			-0.018	0.092
GS, GST		5.239~~4.832~~	5.616~~5.179~~	5.077~~4.683~~	-0.017	0.090
CS		5.239~~4.832~~			-0.017	0.090
LS-1, LS-2		5.169~~4.767~~			-0.003	0.066
GSD Optional						
Secondary		5.239~~4.832~~			-0.014	0.084
Primary		5.187~~4.784~~			-0.014	0.083
Subtransmission		5.134~~4.735~~			-0.014	0.082

Rate Schedules	¢/kWh Fuel Standard	¢/kWh Fuel Peak	¢/kWh Fuel Off-Peak	$/kW Capacity	¢/kWh Environmental
GSD, GSDT, SBD, SBDT					
Secondary	5.239~~4.832~~	5.616~~5.179~~	5.077~~4.683~~	-0.06	0.084
Primary	5.187~~4.784~~	5.560~~5.127~~	5.026~~4.636~~	-0.06	0.083
Subtransmission	5.134~~4.735~~	5.504~~075~~	4.975~~4.589~~	-0.06	0.082
GSLDPR, GSLDTPR	5.187~~4.784~~	5.560~~127~~	5.026~~4.636~~	-0.05	0.076
SBLDPR, SBLDTPR	5.187~~4.784~~	5.560~~127~~	5.026~~4.636~~	-0.05	0.076
GSLDSU, GSLDTSU	5.134~~4.735~~	5.504~~075~~	4.975~~4.589~~	-0.04	0.075
SBLDSU, SBLDTSU	5.134~~4.735~~	5.504~~075~~	4.975~~4.589~~	-0.04	0.075

Continued to Sheet No. 6.021

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE: ~~January 1, 2023~~

Item 9

FILED 2/23/2023
DOCUMENT NO. 01235-2023
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 23, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Engineering (Lewis, Ramos) TB
Division of Accounting and Finance (Veaughn, Sewards) ALM
Division of Economics (Bethea, Hudson) JGH
Office of the General Counsel (Sandy) JSC

RE: Docket No. 20210189-WU – Application for transfer of water facilities of Camachee Island Company, Inc. d/b/a Camachee Cove Yacht Harbor Utility and Certificate No. 647-W to Windward Camachee Marina Owner LLC d/b/a Camachee Cove Yacht Harbor Utility, in St. Johns County.

AGENDA: 03/07/23 – Regular Agenda – Proposed Agency Action for Issues 2 and 3 - Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

Camachee Island Company, Inc. d/b/a Camachee Cove Yacht Harbor Utility (Camachee or Seller) is a Class C water utility providing water service to approximately 68 residential and 28 general service customers in St. Johns County. The Utility is located in the St. Johns River Water Management District (SJRWMD) and is in the Water Resource Caution Area. Wastewater service is provided by the City of St. Augustine. In its 2021 Annual Report, Camachee reported operating revenues of $166,837 and a net operating loss of $20,837.

Camachee began operations in 1977. Camachee was granted an original certificate to operate a water utility in St. Johns County in 1988, subsequent to the county turning jurisdiction over to the Florida Public Service Commission (Commission). The county rescinded our jurisdiction in 1989. The Commission granted a grandfather water certificate to Camachee in 2009, after the county transferred jurisdiction back to the Commission.[1] The Utility's last rate increase was in 2017 through a limited revenue proceeding.[2]

On December 1, 2021, Windward Camachee Marina Owner LLC d/b/a Camachee Cove Yacht Harbor Utility (Windward, Utility, or Buyer) filed an application with the Commission for the transfer of Certificate No. 647-W from Camachee to Windward in St. Johns County, pursuant to Rule 25-30.037(2), Florida Administrative Code (F.A.C.). After the buyer's application was filed with the Commission, the Office of Public Counsel communicated its concerns with the Utility's transfer application in writing and during an informal meeting with the Utility, and Commission staff.[3] As a result, on November 22, 2022, the Utility provided Commission staff with a survey, consisting of a map and description of a recorded water utility easement utilized by Buyer, and the mortgage release executed by the Buyer's lender as requested by Commission staff, in order to process the Utility's application.[4]

This recommendation addresses the transfer of the water system and Certificate No. 647-W and the appropriate net book value of the water system for transfer purposes, and the revision of certain miscellaneous service charges. The Commission has jurisdiction pursuant to Section 367.071, Florida Statutes (F.S.).

[1] Order No. PSC-09-0752-PAA-WU, issued November 16, 2009, in Docket No. 20090185-WU, *In re: Application for grandfather certificate to operate water utility in St. Johns County by Camachee Island Company, Inc. d/b/a Camachee Cove Yacht Harbor Utility.*
[2] Order No. PSC-17-0108-PAA-WU, issued March 27, 2017, in Docket No. 20160145-WU, *In re: Application for limited revenue proceeding in St. Johns County, by Camachee Island Company, Inc. d/b/a Camachee Cove Yacht Harbor Utility.*
[3] Document Nos. 02085-2022, filed March 24, 2022 and 02313-2022, filed April 7, 2022.
[4] Document No. 11758-2022, filed November 29, 2022.

Discussion of Issues

Issue 1: Should the transfer of Certificate No. 647-W in St. Johns County from Camachee Island Company, Inc. d/b/a Camachee Cove Yacht Harbor Utility to Windward Camachee Marina Owner LLC d/b/a Camachee Cove Yacht Harbor Utility, be approved?

Recommendation: Yes. The transfer of the water system and Certificate No. 647-W is in the public interest and should be approved effective the date that the sale becomes final. The resultant Order should serve as the Buyer's certificate and should be retained by the Buyer. The Utility's existing rates and late payment charge, as shown on Schedule No. 3, should remain in effect until a change is authorized by the Commission in a subsequent proceeding. The tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. The Utility is current with respect to regulatory assessment fees (RAFs) and annual reports and should be responsible for filing annual reports and paying RAFs for all future years. (Lewis, Veaughn, Bethea)

Staff Analysis: On December 1, 2021, Windward filed an application for the transfer of Certificate No. 647-W from Camachee to Windward in St. Johns County. The application complies with Section 367.071, F.S., and Commission rules concerning applications for transfer of certificates. The sale to the Buyer occurred on August 31, 2021, contingent upon the Commission's approval, pursuant to Section 367.071(1), F.S.

Noticing, Territory, and Land Ownership

Windward provided notice of the application pursuant to Section 367.071, F.S., and Rule 25-30.030, F.A.C. No objections to the transfer were filed, and the time for doing so has expired. The application contains a description of the service territory, which is appended to this recommendation as Attachment A. Windward provided a copy of a recorded utility easement on November 22, 2022, as evidence that Windward has rights to long-term use of the land upon which the treatment facilities are located pursuant to Rule 25-30.037(2)(s), F.A.C.

Purchase Agreement and Financing

Pursuant to Rule 25-30.037(2)(g),(h) and (i), F.A.C., the application contains a statement regarding financing and a copy of the Purchase Agreement, which included the purchase price, terms of payment, and a list of the assets purchased. There are no customer deposits, guaranteed revenue contracts, developer's agreements, customer advances, leases, or debt of Camachee that must be disposed of with regard to the transfer. According to the Purchase Agreement, the total purchase price for the entire marina, including the water utility assets, is $32,885,000. On November 14, 2022, the Buyer stated the specific purchase price of the water utility assets should be set equal to the net book value (NBV) as established by the Commission.[5] As discussed in Issue 2, staff has calculated a NBV of $228,846 for the water system. Therefore, staff recommends a purchase price of $228,846 for the water utility assets should be recognized.

[5] Document No. 11556-2022.

Facility Description and Compliance

The Utility's water treatment plant is rated at 70,977 gallons per day (gpd). Raw water is drawn from two ground wells and treated by reverse osmosis, aeration, and chlorination. Water is stored in a 24,000-gallon ground tank and a 264-gallon bladder tank before distribution. The Florida Department of Environmental Protection (DEP) conducted an inspection of the water treatment facilities on June 14, 2021, and it was found to be in compliance with the DEP's rules and regulations, including primary and secondary standards.

Technical and Financial Ability

Pursuant to Rule 25-30.037(2)(l) and (m), F.A.C., the application contains statements describing the technical and financial ability of the Buyer to provide service to the proposed service area. As referenced in the transfer application, the Buyer will fulfill the commitments, obligations, and representation of the Seller with regards to utility matters. The Buyer indicated that it has no experience in the water or wastewater industry; however, Windward retained the existing plant operators and office personnel to ensure the continued operation of the water facilities.

Furthermore, the Buyer has stated that it will use its sister company, Windward Marina St. Augustine, to provide funding to the Utility. Staff reviewed the financial statement of Windward Marina St. Augustine, and believes the Buyer has documented adequate resources to support the Utility's operations. Based on the above, staff recommends that the Buyer has demonstrated the technical and financial ability to provide service to the existing service territory.

Rates and Charges

The Utility's rates were last approved in a 2017 limited proceeding rate case for water.[6] Subsequently, the rates have been amended by four price index rate adjustments with the last one being in 2020. The Utility has no initial customer deposits, no service availability charges, and the Utility is built out. The late payment charge was approved in 2009.[7] Rule 25-9.044(1), F.A.C., provides that, in the case of a change of ownership or control of a Utility, the rates, classifications, and regulations of the former owner must continue unless authorized to change by this Commission.

In addition, the Utility has miscellaneous service charges, which were also approved in 2009. However, the miscellaneous service charges do not conform to Rule 25-30.460, F.A.C., and are discussed in Issue 3. Therefore, staff recommends that the Utility's existing rates and late payment charge as shown on Schedule No. 3, should remain in effect, until a change is authorized by the Commission in a subsequent proceeding. The tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C.

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[6] Order No. PSC-17-0108-PAA-WS, issued March 27, 2017, in Docket No. 20160145-WU, *In re: Application for limited revenue proceeding in St. Johns County, by Camachee Island Company, Inc. d/b/a Camachee Cove Yacht Harbor Utility.*

[7] Order No. PSC-09-0752-PAA-WU, issued November 16, 2009, in Docket No. 20090185-WU, *In re: Application for grandfather certificate to operate water utility in St. Johns County by Camachee Island Company, Inc. d/b/a Camachee Cove Yacht Harbor Utility*.

Regulatory Assessment Fees and Annual Report

In its application, the Buyer indicated that it will be responsible for paying the Utility's RAFs and filing its annual reports for the year of transfer and subsequent years. The Seller fulfilled the Utility's RAF and annual report requirements for 2020 and the Buyer fulfilled these requirements for 2021. The Buyer is responsible for the Utility's 2022 RAFs and annual report, which are due by March 31, 2023. Based on the above, staff has verified that the Utility is current with respect to its RAFs and annual reports.

Conclusion

Based on the foregoing, the transfer of the water system and Certificate No. 647-W is in the public interest and should be approved effective the date that the sale becomes final. The resultant Order should serve as the Buyer's certificate and should be retained by the Buyer. The Utility's existing rates and late payment charge, as shown on Schedule No. 3, should remain in effect until a change is authorized by the Commission in a subsequent proceeding. The tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. The Utility is current with respect to regulatory assessment fees (RAFs) and annual reports and should be responsible for filing annual reports and paying RAFs for all future years.

Issue 2: What is the appropriate net book value for the Windward Camachee Marina Owner LLC d/b/a Camachee Cove Yacht Harbor Utility water system for transfer purposes, and should an acquisition adjustment be approved?

Recommendation: The appropriate net book value (NBV) of the water system for transfer purposes is $228,846, as of August 31, 2021. No acquisition adjustment is warranted as the purchase price is equal to NBV. Within 90 days of the date of the final order, the Utility should be required to notify the Commission in writing that it has adjusted its books in accordance with the Commission's decision. The adjustments should be reflected in the Utility's 2022 Annual Report when filed. (Veaughn)

Staff Analysis: Rate base was last established for the Utility as of December 31, 2008.[8] The purpose of establishing NBV for transfers is to determine whether an acquisition adjustment should be approved. The NBV does not include normal ratemaking adjustments for used and useful plant or working capital. The Utility's NBV has been updated to reflect balances as of August 31, 2021. Staff's recommended NBV is shown on Schedule No. 1.

Utility Plant in Service (UPIS)

The Utility reflected a UPIS balance of $573,206 as of August 31, 2021. Audit staff determined the Seller did not make the Commission ordered adjustments established in Order No. PSC-10-1026-PAA-WU to reflect the correct plant balance as of December 31, 2008. Using staff's work papers from the last rate case to establish the beginning balances, and supporting invoices for plant additions, audit staff calculated a UPIS balance of $554,392 as of August 31, 2021. Therefore, staff recommends a UPIS balance of $554,392 as of August 31, 2021.

Land

The Utility reflected a land balance of $10,000 as of August 31, 2021. Camachee's land balance was established in Order No. PSC-2010-1026-PAA-WU. There have been no additions to land since December 31, 2008. Therefore, staff recommends a land balance of $10,000 as of August 31, 2021.

Accumulated Deprecation

The Utility reflected an accumulated depreciation balance of $339,350 as of August 31, 2021. Camachee recorded accumulated depreciation as a grand total; it was not broken down by plant account. Staff auditors recalculated depreciation accruals for all water accounts since the last rate case through August 31, 2021, using the audited UPIS balances and the depreciation rates established by Rule 25-30.140, F.A.C. As a result, staff recommends that the accumulated depreciation balance be decreased by $3,805. Accordingly, staff recommends a total accumulated depreciation balance of $335,545 as of August 31, 2021.

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[8] Order No. PSC-10-0126-PAA-WU, issued March 3, 2010, in Docket No. 20090230-WU, *In re: Application for staff-assisted rate case in St. Johns County by Camachee Island Company, Inc. d/b/a/ Camachee Cove Yacht Harbor Utility.*

Contributions-in-Aid-of-Construction (CIAC) and Accumulated Amortization of CIAC

The Utility reflected CIAC and accumulated amortization of CIAC balances of $0 as of August 31, 2021. The Utility has no authorized service availability charges, and has not received any donated property. Therefore, staff recommends a CIAC balance of $0, and accumulated amortization of CIAC balances of $0, as of August 31, 2021.

Net Book Value

The Utility reflected a NBV of $243,855 as of August 31, 2021. Based on the adjustments described above, staff recommends a NBV of $228,846. Staff's recommended NBV and the National Association of Regulatory Utility Commissioners, Uniform System of Accounts balances for UPIS and accumulated depreciation are shown on Schedule Nos. 1 and 2, as of August 31, 2021.

Acquisition Adjustment

Under Rule 25-30.0371, F.A.C., an acquisition adjustment results when the purchase price differs from the NBV of the assets at the time of the acquisition. As discussed in Issue 1, the Buyer stated the purchase price of the water utility and its assets should be set equal to the NBV established by the Commission. Because the NBV for this Utility at the time of transfer is equal to the purchase price, an acquisition adjustment is not warranted.

Conclusion

Based on the above, staff recommends a NBV of $228,846, as of August 31, 2021. No acquisition adjustment should be included in rate base. Within 90 days of the date of the consummating order, the Buyer should be required to notify the Commission in writing that it has adjusted its books in accordance with the Commission's decision. The adjustments should be reflected in the Utility's 2022 Annual Report when filed.

Issue 3: Should Windward Camachee Marina Owner LLC d/b/a Camachee Cove Yacht Harbor Utility's miscellaneous service charges be revised to conform to amended Rule 25-30.460, F.A.C.?

Recommendation: Yes. The miscellaneous service charges should be revised to conform to the recent amendment to Rule 25-30.460, F.A.C. The tariff should be revised to reflect the removal of the initial connection and normal reconnection charges. Windward should be required to file a proposed customer notice to reflect the Commission-approved charges. The approved charges should be effective on or after the stamped approval date on the tariff sheet pursuant to Rule 25-30.475(1), F.A.C. In addition, the approved charge should not be implemented until staff has approved the proposed customer notice and the notice has been received by customers. The Utility should provide proof of the date notice was given no less than 10 days after the date of the notice. Windward should be required to charge the approved miscellaneous services charges until authorized to change them by the Commission in a subsequent proceeding. (Bethea)

Staff Analysis: Effective June 4, 2021, Rule 25-30.460, F.A.C., was amended to remove initial connection and normal reconnection charges.[9] The definitions for initial connection charges and normal reconnection charges were subsumed in the definition of the premises visit charge. The Utility's miscellaneous service charges consist of initial connection and normal reconnection charges. The normal reconnection charge is more than the premises visit charge. Since the premises visit entails a broader range of tasks, staff believes the premises visit charge should reflect the amount of the normal reconnection charge of $30. Therefore, staff recommends that the initial connection and normal reconnection charges be removed, the premises visit charge should be revised to $30, and the definition for the premises visit charge be updated to comply with amended Rule 25-30.460, F.A.C. The Utility's existing and staff's recommended miscellaneous service charges are shown below in Table 3-1.

Table 3-1
Utility Existing and Staff Recommended Miscellaneous Service Charges

	Utility Existing	Staff Recommended
Initial Connection Charge	$25.00	-
Normal Reconnection Charge	$30.00	-
Violation Reconnection Charge	$30.00	$30.00
Premises Visit Charge	$15.00	$30.00

Conclusion

Based on the above, staff recommends the miscellaneous service charges should be revised to conform to the recent amendment to Rule 25-30.460, F.A.C. The tariff should be revised to reflect the removal of the initial connection and normal reconnection charges. Windward should be required to file a proposed customer notice to reflect the Commission-approved charges. The approved charges should be effective on or after the stamped approval date on the tariff sheet

[9] Order No. PSC-2021-0201-FOF-WS, issued June 4, 2021, in Docket No. 20200240-WS, *In re: Proposed amendment of Rule 25-30.460, F.A.C., Application for Miscellaneous Service Charges.*

pursuant to Rule 25-30.475(1), F.A.C. In addition, the approved charge should not be implemented until staff has approved the proposed customer notice and the notice has been received by customers. The Utility should provide proof of the date notice was given no less than 10 days after the date of the notice. Windward should be required to charge the approved miscellaneous services charges until authorized to change them by the Commission in a subsequent proceeding.

Issue 4: Should this docket be closed?

Recommendation: Yes. If no protest to the proposed agency action is filed by a substantially affected person within 21 days of the date of the issuance of the order, a consummating order should be issued and the docket should be closed administratively upon Commission staff's verification that the revised tariff sheets have been filed, the Buyer has notified the Commission in writing that it has adjusted its books in accordance with the Commission's decision, and proof that appropriate noticing has been done pursuant to Rule 25-30.4345, F.A.C. (Sandy)

Staff Analysis: If no protest to the proposed agency action is filed by a substantially affected person within 21 days of the date of the issuance of the order, a consummating order should be issued and the docket should be closed administratively upon Commission staff's verification that the revised tariff sheets have been filed, the Buyer has notified the Commission in writing that it has adjusted its books in accordance with the Commission's decision, and proof that appropriate noticing has been done pursuant to Rule 25-30.4345, F.A.C.

Windward Camachee Marina Owner LLC
d/b/a Camachee Cove Yacht Harbor Utility

Water Service Area
St. Johns County

Township 7 South, Range 30 East

Sections 5 and 8

Territory description of portions of Sections 5 and 8, Township 7 South, Range 30 East, St. Johns County, Florida, Being more fully described as follows:

For point of reference, commence at an old red cedar post found by previous surveys and described in deeds as marking the Southwest corner of said Government Lot 3, Section 5, Township 7 South, Range 30 East, also being the Point of Beginning; thence North 21˚03'00" West, 686.19'; thence North 60˚12'45" East, 6.66'; thence North 31˚46'56" West, 669.00'; thence North 24˚31'19" West, 1434.26'; thence North 03˚52'55" West, 1638.13'; thence North 08˚52'55" West, 557.00'; thence North 30˚51'32" East, 60.46'; thence North 16˚38'00" West, 70.00'; thence North 03˚38'00" West, 462.00'; thence South 27˚38'00" East, 1452.00'; thence South 02˚38'00" East, 1320.00'; thence South 22˚08'00" East, 462.00'; thence South 73˚38'00" East, 130.00'; thence South 30˚56'51" East, 515.05'; thence South 18˚00'36" West, 478.81'; thence South 38˚34'49" East, 613.35'; thence North 57˚27'21" East, 173.28'; thence North 21˚12'24" West, 76.64'; thence South 75˚55'59" East, 126.55'; thence South 30˚55'59" East, 50.00'; thence South 29˚04'01" West, 70.00'; thence South 16˚39'00" East, 133.08'; thence North 85˚12'32" East, 75.94' to the intersection with a curve being concave to the South, having a radius of 50.00' and Delta of 33˚33'37"; thence along the chord of said curve, North 86˚13'12" East, 28.87'; thence North 07˚10'06" West, 228.78'; thence North 63˚02'16" East, 157' more or less to the mean highwater line; thence Southeasterly, meandering along the mean highwater line, 1200' more or less; thence South 25˚01'07" West, 110.00'; thence South 22˚57'00" East, 24.24'; thence South 67˚03'00" West, 115.75'; thence South 00˚31'00" East, 718.29' to the intersection with a curve being concave to the Southeast having a radius of 2392.00' and Delta of 02˚42'18", said curve also being the Northerly right-of-way line of State Road A-1-A; thence Southwesterly along said curve an arc length distance of 112.93' to the Point of Curvature of said curve; thence South 48˚31'00" West, along said Northerly right-of-way line, 381.63'; thence North 21˚03'00" West, 1022.21' to the Point of Beginning.

FLORIDA PUBLIC SERVICE COMMISSION

Authorizes

Windward Camachee Marina Owner LLC
d/b/a Camachee Cove Yacht Harbor Utility

pursuant to
Certificate Number 647-W

to provide water service in St. Johns County in accordance with the provisions of Chapter 367, Florida Statutes, and the Rules, Regulations, and Orders of this Commission in the territory described by the Orders of this Commission. This authorization shall remain in force and effect until superseded, suspended, cancelled or revoked by Order of this Commission.

Order Number	Date Issued	Docket Number	Filing Type
PSC-09-0752-PAA-WU	11/16/09	20090185-WS	Grandfather Certificate
*	*	20210189-WU	Transfer

***Order Number and date to be provided at time of issuance.**

Windward Camachee Marina Owner LLC
d/b/a Camachee Cove Yacht Harbor Utility

Schedule of Net Book Value as of August 31, 2021

Description	Balance Per Utility	Adjustments	Staff
Utility Plant in Service	$573,205	($18,814)	$554,392
Land & Land Rights	10,000	0	10,000
Accumulated Depreciation	(339,350)	3,805	(335,545)
CIAC	0	0	0
AA of CIAC	0	0	0
Total	$243,855	($15,009)	$228,846

Windward Camachee Marina Owner LLC
d/b/a Camachee Cove Yacht Harbor Utility

Schedule of Staff Recommended Account Balances as of August 31, 2021

Account No.	Description	UPIS	Accumulated Depreciation
304	Structures & Improvements	$204,210	($103,170)
307	Wells and Springs	41,910	(41,910)
309	Supply Mains	14,771	(3,343)
310	Power Generation Equipment	24,827	(4,250)
311	Pumping Equip	19,850	(11,103)
320	Water Treatment Equipment	68,385	(66,559)
330	Distribution Reservoirs	80,515	(34,158)
331	Transmission and Distribution Mains	85,131	(61,990)
334	Meter and Meter Install.	10,241	(6,391)
340	Office Furniture & Equip.	377	(377)
347	Misc. Equip	4,175	(2,296)
	Total	**$554,392**	**($335,547)**

Windward Camachee Marina Owner LLC
d/b/a Camachee Cove Yacht Harbor Utility

Monthly Water Rates

Residential and General Service

<u>Base Facility Charge by Meter Size</u>	
5/8" x 3/4"	$21.35
3/4"	$32.03
1"	$53.38
1-1/2"	$106.75
2"	$170.80
3"	$341.60
4"	$533.75
6"	$1,067.50
Charge Per 1,000 gallons – Residential	
0 – 3,000 gallons	$3.48
3,001 – 6,000 gallons	$10.37
6,001 – 12,000 gallons	$15.57
Over 12,000 gallons	$20.74
Charge Per 1,000 gallons – General Service	$13.89
Flat Rate – General Service	$109.72

Private Fire Protection

<u>Base Facility Charge by Meter Size</u>	
5/8" x 3/4"	$1.78
3/4"	$2.67
1"	$4.45
1 1/2"	$8.90
2"	$14.23
3"	$28.47
4"	$44.48
6"	$88.96

Miscellaneous Service Charges

Late Payment Charge	$5.00

Item 10

FILED 2/23/2023
DOCUMENT NO. 01236-2023
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER ● 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: February 23, 2023

TO: Office of Commission Clerk (Teitzman)

FROM: Division of Economics (Bruce, Bethea, Hudson) JGH
Division of Accounting and Finance (Sewards) ALM
Office of the General Counsel (Crawford, Sandy, Thompson) JSC

RE: Docket No. 20220201-WS – Request by Florida Community Water Systems, Inc. for a revenue-neutral rate restructuring in Brevard, Lake, and Sumter Counties.

AGENDA: 03/07/23 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: La Rosa

CRITICAL DATES: 03/07/23 (90-day statutory deadline waived until 03/07/23)

SPECIAL INSTRUCTIONS: None

Case Background

On November 14, 2022, Florida Community Water Systems, Inc. (FCWS) filed an application for a revenue-neutral rate restructuring limited proceeding for the fourteen water and wastewater systems it owns in Brevard, Lake, and Sumter counties. FCWS is seeking a rule waiver to use the limited proceeding rule, Rule 25-30.445, Florida Administrative Code (F.A.C.), to consolidate these systems for ratemaking purposes.

The ten water systems at issue here are Black Bear Waterworks, Inc. (Black Bear); Brendenwood Waterworks, Inc.; Brevard Waterworks, Inc.; Harbor Waterworks, Inc. (Harbor); Jumper Creek Utility Company (Jumper Creek); Lake Idlewild Utility Company; Lakeside Waterworks, Inc. (Lakeside); Pine Harbour Waterworks, Inc.; Raintree Waterworks, Inc.; and The Woods Utility

Company. Four of these systems also have wastewater systems: Harbor, Jumper Creek, Lakeside, and The Woods Utility Company. By Order No. PSC-2022-0095-FOF-WS, the Commission acknowledged the corporate reorganization and name change of these systems to FCWS.[1] The corporate reorganization resulted in no change in the ownership or control of the utilities, and each FCWS system continues to charge its own respective Commission-approved rates and charges.

In its November 14, 2022, petition for limited proceeding, FCWS seeks uniform rates for these systems. FCWS states that the various rates charged by each system are widely disparate. Uniform rates, if granted, would result in a reduction in typical residential bills, except for Lakeside wastewater customers and all Harbor customers, and would provide significant relief to the customers in the financially distressed systems.

The Commission has broad authority to conduct limited proceedings under Section 367.0822(1), Florida Statutes (F.S.). Rule 25-30.445, F.A.C., which the Commission adopted to implement Section 367.0822, F.S., restricts the ability of water and wastewater systems to use the limited proceeding process. Rule 25-30.445(6), F.A.C., provides that a limited proceeding will not be allowed if:

> (a) The utility's filing includes more than six separate projects for which recovery is sought. Corresponding adjustments for a given project are not subject to the above limitation;
> (b) The requested rate increase exceeds 30 percent;
> (c) The utility has not had a rate case within seven years of the date the petition for limited proceeding is filed with the Commission; or
> (d) The limited proceeding is filed as the result of the complete elimination of either the water or wastewater treatment process.

FCWS argues that Rule 25-30.445, F.A.C., seems to contemplate a petition for limited proceeding is predicated upon a rate increase. However, FCWS is requesting a revenue-neutral rate restructuring based upon existing historical revenues, not a revenue increase. Further, FCWS recognizes that not all of its systems meet the seven-year rate case requirement of Rule 25-30.445(6)(c), F.A.C. Consequently, on December 5, 2022, FCWS filed a request for a partial variance from, or waiver of, the requirements of the rule governing limited proceedings.

Florida law allows agencies to waive or provide other relief (variances) to persons subject to regulation where the strict application of uniformly applicable rule requirements leads to "unreasonable, unfair, and unintended results in particular instances." Section 120.542(1), F.S.

[1] Issued February 21, 2022, in Docket No. 20210192-WS, *In re: Joint application for acknowledgment of corporate reorganization and approval of name changes on Certificate No. 654-W in Lake County from Black Bear Waterworks, Inc., Certificate No. 339-W in Lake County from Brendenwood Waterworks, Inc., Certificate No. 002-W in Brevard County from Brevard Waterworks, Inc., Certificate Nos. 522-W and 565-S in Lake County from Harbor Waterworks, Inc., Certificate Nos. 667-W and 507-S in Sumter County from Jumper Creek Utility Company, Certificate No. 531-W in Lake County from Lake Idlewild Utility Company, Certificate Nos. 567-W and 494-S in Lake County from Lakeside Waterworks, Inc., Certificate No. 450-W in Lake County from Pine Harbour Waterworks, Inc., Certificate No. 539-W in Lake County from Raintree Waterworks, Inc., Certificate Nos. 507-W and 441-S in Sumter County from The Woods Utility Company to Florida Community Water Systems, Inc.*

Variances and waivers shall be granted when the person subject to the rule demonstrates that the purpose of the underlying statute will be or has been achieved by other means by the person and when application of a rule would create a substantial hardship or would violate principles of fairness. Section 120.542(2), F.S.

On December 8, 2022, the Commission filed a Florida Administrative Register notice acknowledging receipt of FCWS's rule waiver petition. The time for filing comments, provided by Rule 28-104.003, F.A.C., expired on December 23, 2022; no comments as to FCWS's rule waiver petition were received. On January 5, 2023, FCWS waived the 90-day deadline for the Commission to grant or deny its petition, pursuant to Section 120.542(8), F.S., through the March 7, 2023, Commission Agenda Conference. Thereafter, on January 6, 2023, FCWS filed a supplement to its application and petition for waiver.

This recommendation addresses FCWS's petition for rule waiver only. If the Commission approves FCWS's request for rule waiver, a subsequent recommendation addressing the merits of FCWS's application for a rate restructuring will be presented at a subsequent Agenda Conference. The Commission has jurisdiction under Sections 120.542, 367.0822, and 367.121, F.S.

Discussion of Issues

Issue 1: Should the Commission grant FCWS's petition for a waiver of Rule 25-30.445(6), F.A.C.?

Recommendation: Yes. FCWS has demonstrated that the purpose of the underlying statute is being achieved and that strict application of the rule violates principles of fairness to its customers. (Thompson, Sandy, Crawford)

Staff Analysis:

FCWS's Petition

In its November 14, 2022, petition for limited proceeding, FCWS states that the various rates reflect a wide disparity among its systems. Several systems have had multiple rate cases before the Commission due to increased capital requirements, increased operating expenses, and declining consumption. Others – Harbor and Black Bear – have never had a rate case before the Commission. FCWS contends that the implementation of uniform rates would be more efficient and result in a more equitable disbursement of operating costs among the customers of the FCWS systems. FCWS contends that the uniform rates, if granted, would result in a reduction in typical residential water bills, with the exception of Harbor, and would provide significant relief to the customers in the financially distressed systems.

FCWS's application seeks to achieve a revenue-neutral rate restructuring through a limited proceeding instead of through a full rate case, which, because of rate case expense, it contends would negate the savings to customers and may counterproductively result in a rate decrease for Harbor. FCWS acknowledges that neither Harbor nor Black Bear have had a full rate case, and it has been 8 years since the Commission set rates for Brevard Waterworks, Inc. and Jumper Creek.[2]

One system in particular, Harbor, would benefit from conservation rates. Harbor has relatively low rates and has consumed water beyond the limit of the utility's consumptive use permit. The utility has begun working with the local water management district and has retained a conservation expert for irrigation audits. Despite these efforts, the customers of the utility continue to use excessive amounts of water. According to FCWS, numerous customers in Harbor are regularly using over 100,000 and 200,000 gallons of water per month.

Another system, Black Bear, would likewise benefit from conservation rates. For Black Bear, the base facility charge includes the first 5,000 gallons of water usage. FCWS asserts that including

[2] *See* Order No. PSC-11-0478-PAA-WU, issued October 24, 2011, in Docket No. 100085-WU, *In re: Application for certificate to operate water utility in Lake County by Black Bear Reserve Water Corporation*; Order No. PSC-12-0580-PAA-SU, issued October 26, 2012, in Docket No. 120158-SU, *In re: Application for original certificate for an existing wastewater system, requesting initial rates and charges in Lake County by Harbor Waterworks, Inc.;* PSC-15-0335-PAA-WS, issued August 20, 2015, in Docket No. 20140147-WS, *In re: Application for staff-assisted rate case in Sumter County by Jumper Creek Utility Company*; and Order No. PSC-16-0421-PAA-WU, issued October 3, 2016, in Docket No. 20140186-WU, *In re: Application for staff-assisted rate case in Brevard County by Brevard Waterworks, Inc.*

water as part of the base facility charge is contrary to Florida's conservation efforts. Additionally, FCWS believes it would be more efficient to have a uniform rate structure for all of its systems.

FCWS seeks an inclining block rate structure on all ten of its water systems. As a result of the requested rate restructuring, FCWS projects that residential water bills would be reduced at all levels for eight of the ten systems. The only systems that would see a rate increase are the Harbor system, where FCWS expects a repression of usage from the new conservation rates, and the Lakeside wastewater customers. Per FCWS's projections, the customers of some systems could see their monthly water bills drop by as much as $134.21. Harbor's bills, however, would only increase by $9.92 at the 10,000-gallon level for water, by $12.43 at the 10,000-gallon level for wastewater, and by even less at lower consumption levels. Lakeside's wastewater bill would increase by $5.53 at the 3,000-gallon level and would actually result in $0.83 in savings at the 10,000-gallon level. However, rate changes to certain classes and meter sizes for both of the Harbor systems and Lakeside's wastewater system exceed the 30 percent limitation set by Rule 25-30.445(6)(b). Therefore, parts (b) and (c) would both have to be waived.

FCWS contends that the purpose of the statute is to afford the Commission broad discretion as to matters that are appropriate for a limited proceeding in order to alleviate the time and expense of full rate proceedings. As to the requirement that a utility can avail itself to a limited proceeding only if it has had a rate case within the last seven years, FCWS states that although there is "nothing magic" about seven years, it was intended to assure that when a limited proceeding rate increase was considered, the utility's overall financial information had been vetted in recent years by the Commission. FCWS argues that when the limited proceeding doesn't seek a revenue increase (other than for rate case expense), that vetting is not necessary. Further, FCWS believes the underlying purpose of the statute would be achieved if a waiver or variance is granted because the Commission would retain its right to obtain information required to achieve the appropriate rate consolidation, including conducting an audit, if necessary.

Requirements of Section 120.542, F.S.

Section 120.542(2), F.S., provides a two-pronged test for determining when waivers of and variances from agency rules shall be granted:

> . . . when the person subject to the rule demonstrates that the purpose of the underlying statute will be or has been achieved by other means by the person and when application of the rule would create a substantial hardship or would violate principles of fairness. For purposes of this section, "substantial hardship" means demonstrated economic, technological, legal or other type of hardship to the person requesting the variance or waiver. For purposes of this section, "principles of fairness" are violated when the literal application of a rule affects a particular person in a manner significantly different from the way it affects other similarly situated persons who are subject to the rule.

Purpose of the Underlying Statute

Rule 25-30.445, F.A.C., primarily implements Section 367.0822, F.S.,[3] which authorizes the Commission to "conduct limited proceedings to consider, and act upon, any matter within its jurisdiction . . . ." Rule 25-30.445(6), F.A.C., serves to limit the matters that the Commission may take up via a limited proceeding. The Commission has previously opined as to the underlying purpose of Section 367.0822, F.S.:

> We believe that the purpose of the Legislature in enacting Section 367.0822, Florida Statutes (1985), was to provide a narrow exception to Section 367.081, Florida Statutes (1985), which requires the Commission to consider a broad range of ratemaking components. The purpose of a limited proceeding is to permit review of generally singular topics, or a few well-defined issues, to the exclusion of all others. The limited applicability of such a proceeding mandates that the burden must rest on the utility to prove that Section 367.0822, Florida Statutes (1985) should, in fact, be utilized with regard to a specific case.[4]

While the Commission has approved prior rate consolidations in the context of full rate case proceedings,[5] there is no statutory requirement that rate consolidations must be conducted under Section 367.081, F.S., versus a Section 367.0822, F.S., proceeding. Further, the Commission has allowed revenue-neutral rate restructuring through a limited proceeding on prior occasions.[6]

The limitations set out under Rule 25-30.445, F.A.C., are unique to the water and wastewater industry. Section 366.076, F.S., provides for petitions for limited proceedings by electric and gas companies, and its associated Rule 25-6.0431, F.A.C., does not contain the same limiting provisions as Rule 25-30.455, F.A.C. The purpose of Section 367.0822, F.S. – to allow the Commission to review the singular issue of a revenue-neutral consolidation of the FCWS systems' rates – is met if Rule 25-30.445(6), F.A.C., is waived. As acknowledged by FCWS, the Commission would retain its authority to solicit any information needed to process the requested rate consolidation, including conducting an audit if necessary, as well as continue regulatory oversight and earnings' surveillance through FCWS's annual reports. Staff therefore recommends that FCWS has demonstrated that the purpose of the underlying statute would be achieved if the requirements of Rule 25-30.445(6), F.A.C., are waived.

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[3] Rule 25-30.445, F.A.C., also implements Sections 367.081, 367.0812, 367.121(1)(a), and 367.145(2), F.S.

[4] Order No. 16670, issued October 2, 1986, in Docket No. 861056-SU, *In re: Petition of Betmar Utilities for Limited Proceeding for Adjustment in Sewer Rate Base in Pasco County* and PSC-2010-0219-PAA-WS.

[5] *See, e.g.,* Order No. PSC-2017-0361-FOF-WS, issued September 25, 2017, in Docket No. 20160101-WS, *In re: Application for increase in water and wastewater rates in Charlotte, Highlands, Lake, Lee, Marion, Orange, Pasco, Pinellas, Polk, and Seminole Counties by Utilities, Inc. of Florida.*

[6] Order Nos. PSC-95-0967-FOF-SU, issued August 8, 1995, in Docket No. 19941270-SU, *In re: Application for revenue neutral wastewater rate restructuring in Lee county by Forest Utilities, Inc*. and PSC-10-0219-PAA-WS, issued April 6, 2010, in Docket No. 20080295-WS, *In re: Request by Sun Communities Finance, LLC d/b/a Water Oak Utility for a revenue-neutral rate restructuring to implement conservation rates in Lake County.*

Substantial Hardship or Principles of Fairness

The second prong of the rule waiver test is met if strict application of the rule either (1) creates a substantial hardship or (2) would violate the principles of fundamental fairness. The utility may meet the second prong through either path and is not required to show both.

In its petition, FCWS argues that denying the rule waiver would result in an economic hardship as it would require FCWS to file for a full rate case in order to achieve consolidation of its systems' rates. A full rate case would involve compiling and filing ten separate sets of Minimum Filing Requirements and retaining outside legal counsel, the costs of which would reduce or obviate any customer savings as a result of the rate restructuring. While the costs of a full rate proceeding may be substantial, staff is not persuaded that such costs per se constitute an "economic hardship" *to the utility* sufficient to support waiver of the rule. While *customers* might pay substantially more for rate consolidation effected under a Section 367.081, F.S., rate proceeding, subsection 367.081(7), F.S., permits the *utility* to recover its reasonable rate case expense through rates paid by its customers.

However, the second prong of the rule waiver statute may also be met when application of the rule would violate principles of fairness. "Principles of fairness" are violated when the literal application of a rule affects a particular person in a manner significantly different from the way it affects other similarly situated persons who are subject to the rule. Section 120.542(2), F.S.

In its January 6, 2023, supplemental filing, FCWS states that the Commission has a long-standing policy of encouraging the consolidation of smaller systems, and that the natural progression from the consolidation of systems is the consolidation of rates. Further, the Commission has previously noted the benefits of rate consolidation to both utilities and their customers.[7] Specifically, in Order No. PSC-2010-0219-PAA-WS for Betmar Utilities, the Commission stated that "a revenue neutral rate restructuring for a Class B utility is tantamount to a limited proceeding rate case with no revenue increase." In that case, the Commission considered the need for a conservation-oriented rate structure in making its decision.

FCWS is uniquely affected by the strict application of the rule. Because Black Bear and Harbor's existing rates were grandfathered in at the time they were certificated, those systems have never had a full rate case before the Commission. However, Harbor continues to consume significant amounts of water, with numerous customers consistently using up to 200,000 gallons per month. This is in conflict with Florida's water conservation efforts, and the St. Johns River Water Management District (SJRWMD) has worked with Harbor to address the exceedance of Harbor's consumptive use permit. Harbor and the SJRWMD have attended meetings of the Harbor homeowners' association, and FCWS retained a conservation expert to conduct on-site irrigation audits at the customers' residences. In spite of these efforts, the usage of customers served by

[7] The Commission has found that consolidated, uniform rates provide the customers with greater control over their water bill and provides the utility with a less complicated and expensive billing procedure. *See* Order No. 13014, issued February 20, 1984, in Docket No. 810386-WU, *In re: Request of Sunshine Utilities, Inc. for Staff Assistance on a Rate Increase to Customers in Marion County, Florida*, at p. 3 and Order No. PSC-2017-0361-FOF-WS, issued September 25, 2017, in Docket No. 20160101-WS, *In re: Application for increase in water and wastewater rates in Charlotte, Highlands, Lake, Lee, Marion, Orange, Pasco, Pinellas, Polk, and Seminole Counties by Utilities, Inc. of Florida*, at p. 189.

Harbor remains excessive, and the low rates do not send appropriate conservation signals to Harbor's customers. FCWS has also been unable to implement conservation rates due to Harbor's relatively low revenue requirement.

Allowing FCWS to pursue a revenue-neutral rate restructuring and consolidate its systems' rates through a limited proceeding is expected to allow the majority of FCWS's customers to benefit from lower rates, send more appropriate conservation-oriented price signals to Harbor's customers, simplify FCWS's tariffs, and create regulatory efficiencies that benefit the FCWS systems and its customers alike. Requiring FCWS to pursue these goals through a full base rate proceeding would unfairly minimize or obviate the benefits of consolidation by adding the additional time and rate case expense required to process an application pursuant to Section 367.081, F.S.

Staff recommends that a limited proceeding will allow the Commission to maintain appropriate regulatory oversight of the proposed rate consolidation, to the benefit of the utility and its customers. Under the unique circumstances of this case, the potential benefits to the utility and its customers stand to be lost if FCWS is not permitted to pursue the proposed revenue-neutral rate restructuring as a limited proceeding. Therefore, staff recommends that strict application of the rule would violate the principles of fairness.

Conclusion

Section 120.542(1), F.S., acknowledges that strict application of uniformly applicable rule requirements can lead to unreasonable, unfair, and unintended results in particular instances. The Commission must waive a rule if the utility can show both that the purpose of the underlying statute is achieved by other means, and that the principles of fairness are violated if the rule is strictly applied. This case presents a unique situation wherein the strict application of the rule affects FCWS significantly differently than it would another utility, and the petition meets both prongs of the test. Therefore, staff recommends the Commission grant the petition for waiver of Rule 25-30.445(6), F.A.C.

Issue 2: Should this docket be closed?

Recommendation: If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the order, a consummating order should be issued. If the utility's petition for a rule waiver is granted, then the docket should remain open pending the Commission's decision regarding FCWS's petition for a limited proceeding. However, if the utility's petition for a rule waiver is denied, then the docket should be closed upon the issuance of the consummating order. (Thompson, Sandy, Crawford)

Staff Analysis: If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the order, a consummating order should be issued. If the utility's petition for a rule waiver is granted, then the docket should remain open pending the Commission's decision regarding FCWS's petition for a limited proceeding. However, if the utility's petition for a rule waiver is denied, then the docket should be closed upon the issuance of the consummating order.