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Commission Conference Agenda
May 8, 2018

Item 1

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: April 26, 2018

TO: Office of Commission Clerk (Stauffer)

FROM: Office of Industry Development and Market Analysis (C. Williams) CW AT CH
Office of the General Counsel (R. Trice) RPT CM

RE: Application for Certificate of Authority to Provide Telecommunications Service

AGENDA: 5/8/2018 - Consent Agenda - Proposed Agency Action - Interested Persons May Participate

SPECIAL INSTRUCTIONS: None

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

DOCKET NO.	COMPANY NAME	CERT. NO.
20180093-TX	Call One Inc. of Illinois	8920

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 entity 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: April 26, 2018

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (M. Watts, Graves)
Division of Accounting and Finance (Norris, Sewards)
Division of Economics (Friedrich, Hudson)
Office of the General Counsel (Crawford)

RE: Docket No. 20160220-WS-Application for original water and wastewater certificates in Sumter County, by South Sumter Utility Company, LLC.

AGENDA: 05/08/18 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Clark

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On October 11, 2016, South Sumter Utility Company, L.L.C. (SSU or Utility) filed its application for original water and wastewater certificates in Sumter County. The area is in the Southwest Florida Water Management District (SWFWMD) and is not in a water use caution area.

Concurrent with its application for original water and wastewater certificates, the Utility also filed a petition for a temporary waiver of Rules 25-30.033(1)(p) and (q), Florida Administrative Code (F.A.C.), in order to bifurcate the certification and rate setting aspects of the case. The Florida Public Service Commission (Commission) granted Certificate Nos. 669-W and 571-S to SSU to provide water and wastewater service in Sumter County, and granted its request for temporary rule waiver.[1] In the Order granting the waiver, the Commission required SSU to file supporting financial information to establish rates and charges by September 29, 2017.

On September 27, 2017, SSU filed a letter advising staff that, due to Hurricane Irma, there would be a two-week delay in filing the supporting financial information required to establish rates and charges. SSU filed the required information on October 12, 2017. This recommendation addresses the initial rates and charges for the Utility's water and wastewater services. The Commission has jurisdiction pursuant to Sections 367.031, 367.045, 367.081, 367.091 and 120.452, Florida Statutes (F.S.).

[1]Order No. PSC-17-0059-PAA-WS, issued February 24, 2017, in Docket No. 20160220-WS, *In re: Application for original water and wastewater certificates in Sumter County, by South Sumter Utility Company, LLC.*

Discussion of Issues

Issue 1: What are the appropriate water and wastewater rates and return on investment for South Sumter Utility Company, LLC?

Recommendation: Staff's recommended water and wastewater rates, shown on Schedule Nos. 4-A and 4-B, are reasonable and should be approved. The approved rates should be effective for services rendered or connections made on or after the stamped approval date on the tariff sheets, pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved rates until authorized to change them by the Commission in a subsequent proceeding. A return on equity of 8.74 percent plus or minus 100 basis points should also be approved. (Graves, M. Watts, Sewards, Friedrich)

Staff Analysis: In setting initial rates and charges for a new utility, Commission practice has been to set rates so that the utility will have an opportunity to earn a fair return on its investment when approximately 80 percent of its projected customers are being served.[2] Typically, in the early years of development, the customer base of a utility is not sufficient to allow the utility to recover its operating and maintenance (O&M) expenses and earn a fair return on its investment. However, as growth reaches 80 percent of a utility's projected design capacity, the initial rates become compensatory.

Pursuant to the requirements of Rule 25-30.033, F.A.C., SSU's filing included schedules intended to show projected plant, operating expenses, and capital structure when the system is operating at 80 percent of the design capacity. The Utility additionally provided proposed tariffs as well as an engineer's report, to support the rates and charges contained in the tariffs. Staff has reviewed the SSU's filing and recommends several adjustments which are discussed below.

Description of the Utility's Service

SSU anticipates providing water and wastewater service to 8,200 residential units as well as an estimated 153 commercial connections at build-out (projected to occur by 2023). The area to be served will be part of The Villages development (Villages), which is a retirement community in central Florida.

The Utility will construct, operate, and maintain the water distribution system within its service territory, while purchasing bulk potable water and fire flow from the City of Wildwood (Wildwood or City). Pursuant to the Utility's franchise agreement with Wildwood, SSU agreed to purchase bulk water from the City. As part of SSU's purchase agreement with Wildwood, SSU committed to construct a water treatment plant (WTP) and transfer the facility to the City for ownership, operation, and maintenance. The Utility determined it would build the WTP to the

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[2]Order Nos. PSC-11-0113-PAA-WS, issued February 11, 2011, in Docket No. 20050192-WS, *In re: Application for certificates to provide water and wastewater service in Sumter County by Central Sumter Utility Company, L.L.C.* and PSC-17-0113-PAA-WS, issued March 28, 2017, in Docket No. 20130105-WS, *In re: Application for certificates to provide water and wastewater service in Hendry and Collier Counties, by Consolidated Services of Hendry & Collier, LLC.*

same standard as the other WTPs serving the Villages, in lieu of paying capacity and connection fees.

In response to a staff data request, the Utility stated "while it would have preferred to own and operate the WTP, the territory to be served is within the City of Wildwood, which has the first right to provide such service." SSU asserted that City of Wildwood resolutions and Chapter 180, F.S., established Wildwood's right to provide water and wastewater service.

Pursuant to the previously discussed purchase agreement, the City of Wildwood will also temporarily treat and dispose of wastewater generated by SSU. This term of the agreement is intended to allow sufficient time for the Utility to construct a wastewater transmission connection to the City of Leesburg's Turnpike Wastewater Treatment Facility. Upon completion of the connection to the City of Leesburg, currently anticipated to occur in April 2019, wastewater will be treated and disposed of in perpetuity through an agreement with the City of Leesburg. SSU will construct, operate, and maintain the wastewater collection and transmission system within its service area. In response to a staff data request the Utility stated that the costs of temporary interconnections with Wildwood's system as well as interim rates paid to Wildwood were not included in its requested rates.

Projected Rate Base

In support of its proposed rates and charges, SSU provided an engineering study, prepared by Farner, Barley & Associates, Inc., which includes data related to projected costs as well as customer growth. Farner, Barley & Associates, Inc. performed a similar study for Central Sumter Utilities (CSU), which was granted initial rates and charges by the Commission in 2011.[3] Staff believes that the estimates and projections included in the engineering study are reasonable because they are based on historical data within the Villages.

Based on SSU's growth projections, the Utility anticipates operating at 80 percent of its design capacity in 2021. In its filing, SSU presented its projected costs for Utility Plant in Service (UPIS) as $30,098,803 for its water system and $41,797,661 for its wastewater systems. The UPIS presented in SSU's filing included costs through 2022; therefore, the UPIS was not properly adjusted to reflect 80 percent of design capacity. In response to a staff request, the Utility acknowledged that adjustments to its water distribution system and its wastewater collection and transmission system were necessary.

Based on the growth projections provided by SSU, staff recommends a reduction of $4,467,016 for water and $5,013,811 for wastewater to reflect plant at 80 percent of design capacity. Staff's reductions are based on 80 percent design capacity occurring approximately mid-year 2021. Staff notes that a similar approach was used in calculating UPIS for the initial rates and charges that were approved for CSU.

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[3]Order No. PSC-11-0113-PAA-WS, issued February 11, 2011, in Docket No. 20050192-WS, *In re: Application for certificates to provide water and wastewater service in Sumter County by Central Sumter Utility Company, L.L.C.*

As previously discussed, the Utility is proposing to construct a water treatment plant, donate the plant to Wildwood, purchase water from Wildwood, and include the cost of the plant ($8,544,833) as intangible plant for rate setting purposes. Under traditional purchased water agreements, the purchasing utility would pay an impact fee for plant capacity. In response to a staff data request, SSU states that Wildwood estimated the total impact fee to connect its water system to SSU's water system would be $5,180,610. Based on the discussion above, staff recommends the Commission include Wildwood's estimated impact fee as intangible plant as opposed to the total cost of the WTP at this time. This results in a reduction of $3,364,223 to intangible plant.

Based on the discussion above, staff recommends a reduction to SSU's projected plant in service of approximately $7,831,240 for water, and $5,013,811 for wastewater. Staff notes that actual costs will be addressed when the Utility comes in for a rate case.

In its filing, SSU projected contributions in aid of construction (CIAC) balances of $15,264,648 and $17,584,812 for the water and wastewater systems, respectively, based on its proposed plant capacity charges of $1,954 per equivalent residential connection (ERC) for water and $2,251 per ERC for wastewater. As discussed in Issue 10, staff is recommending a main extension charge of $1,916 for water and $2,610 for wastewater. In addition, staff is recommending a plant capacity charge of $450 for wastewater. As such, staff recalculated the projected CIAC balances as a corresponding adjustment. Consistent with the adjustment to plant discussed above, staff adjusted the total ERCs used in its recalculation to recognize 80 percent of design capacity. To recognize the foregoing adjustments, staff recommends a decrease to projected CIAC of $2,171,470 for water, and an increase of $3,326,003 for wastewater.

SSU's projected balances of accumulated depreciation and amortization of CIAC for the water system are based on the average service life guidelines, as set forth in Rule 25-30.140, F.A.C. However, the projected amounts for the wastewater system reflect one account that does not follow the guidelines and requires correction. Additionally, corresponding adjustments should be made to both the water and wastewater systems to reflect staff's recommended adjustments to plant and CIAC. In total, staff recommends decreasing projected accumulated depreciation by $947,770 for water and $56,898 for wastewater. Further, projected accumulated amortization of CIAC should be decreased by $12,667 for water and increased by $343,628 for wastewater.

The Utility projected a working capital allowance of $191,984 for water and $188,054 for wastewater based on one-eighth of the estimated O&M expense for each system. Staff recommends a reduction of $37,575 for water and wastewater, each, to reflect staff's recommended adjustments to O&M expense discussed in the revenue requirement section below.

In total, SSU projected a water rate base of $13,405,856 and a wastewater rate base of $22,059,341. Based on the adjustments discussed above, staff recommends that the projected rate base for water be reduced by $4,762,241 and that the projected rate base for wastewater be reduced by $7,976,863. Staff believes the adjusted rate base projections of $8,643,615 for water and $14,082,478 for wastewater are reasonable and should be approved. Rate base calculations for the water and wastewater systems are shown on Schedule Nos. 1-A and 1-B, respectively. Staff's adjustments are shown on Schedule No. 1-C. Consistent with Commission practice in applications for original certificates, projected rate base is established only as a tool to aid the Commission in setting initial rates and is not intended to formally establish rate base.

Cost of Capital

In a deficiency response letter dated November 17, 2017, the Utility provided a projected capital structure at 80 percent of the design capacity, including an assertion that the methods of financing the construction and operation for the Utility remain unchanged from the original application. SSU stated that the initial capitalization and Utility operations will be funded 100 percent through equity provided by the developer of the proposed service area.[4]

SSU proposed a cost of equity of 8.76 percent. Although the Utility reflected the Commission's most recent leverage formula,[5] it incorrectly calculated one of the variables. The Utility included customer deposits to calculate an equity ratio of 98.52. However, the equity ratio should only reflect investor sources of capital and not include customer deposits. The correct equity ratio of 100 percent results in a cost of equity of 8.74 percent.

In the projected capital structure provided by the Utility, customer deposits were listed at $526,386. On March 6, 2018, staff contacted SSU for clarification on the calculation of customer deposits, as detailed on lines 19-21 of the projected capital structure. In response, the Utility provided the anticipated customer growth between 2018 and 2022,[6] which indicated that the Utility based its calculation on an incorrect time period. The appropriate time period to calculate customer deposits should be between 2020 and 2021. Staff recalculated projected customer deposits to reflect the balance at 80 percent of design capacity. As such, staff recommends an increase of $269,987 to customer deposits for a total of $796,373.

Based on the adjustments above, staff recommends an overall cost of capital of 8.50 percent. The appropriate return on equity for SSU is 8.74 percent, with a range of plus or minus 100 basis points, as shown on Schedule No. 2.

Net Operating Income

SSU requested net operating income (NOI) for the water and wastewater systems of $708,684 and $908,221, respectively, based on the projected rate base of each system and a projected overall cost of capital of 5.29 percent for water and 4.12 percent for wastewater. The Utility explained that it was requesting rates which will generate less than the allowed rate of return by reducing the revenues of the revenue requirement it originally projected. SSU stated that its intent was to attempt to more closely match the rates of other area residents while maintaining financial viability. Staff's recommended NOI of $735,037 for water and $1,197,548 for wastewater reflects the full return on investment resulting from recommended projections of rate base and overall cost of capital. The projected NOI for the water and wastewater systems are shown in Schedule Nos. 3-A and 3-B, respectively.

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[4]Document No. 09911-2017.
[5]Order No. PSC-2017-0249-PAA-WS, issued June 26, 2017, in Docket No. 20170006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*
[6]Document No. 02158-2018.

Revenue Requirement

The Utility's projected revenues include O&M expenses, depreciation and CIAC amortization expense, taxes other than income, as well as a return on investment. As a limited liability company, SSU has no income tax expense. Staff believes adjustments are necessary, as addressed below.

Operation and Maintenance Expense

The Utility projected contractual services expense in the amounts of $903,893 for water and $925,737 for wastewater. SSU's contractual services expense is comprised of management fees, distribution/collection contractor fees, and engineering fees. Staff recommends adjustments to management and engineering fees as discussed below.

The Utility proposed total management fees of $751,776, split evenly between the water and wastewater systems at $375,888 each. In response to staff's data requests, SSU provided information detailing how the management fee was derived. The Utility used CSU's average monthly O&M expenses attributable to management activities included in its customer management fee to develop SSU's projected management fees. Staff believes CSU is an appropriate company to develop projected fees, as both utilities will have similar fees assessed for management and accounting services from The Villages and Village Center Community Development District (VCCDD). These entities handle management and accounting services for SSU and CSU.

Using CSU's average monthly costs for management services of approximately $97,700, as broken out in Table 1-1 below, SSU estimated a monthly fee of $7.96 per customer. The Utility also included an additional 10 percent for an escalation adjustment ($0.80), as well as 10 percent for a contingency adjustment ($0.80), for a total of $9.55 ($7.96 + $0.80 + $0.80).

Staff reviewed the components of CSU's average monthly costs used to calculate the management fee and believes adjustments are necessary. Staff believes the rent expense, insurance, and organizational costs are duplicative of what is included in overhead fees and contractual services to VCCDD. In addition, inclusion of regulatory assessment fees (RAFs) and property tax are duplicative, as the Utility will recover these items through the revenue requirement. In response to staff's data request, the Utility acknowledged that SSU would have 100 percent equity financing provided by the developer, and would not have an interest expense. SSU acknowledged the error and agreed this expense should be removed from the amount used to develop the Utility's management fee. Staff recommends the amount used to develop the Utility's management fee should be reduced by $70,800, resulting in a total monthly expense of $26,800. Table 1- 1 below summarizes staff's adjustments.

Table 1-1
Monthly Management Fees

Expenses	Utility	Staff
CSU Overhead Fees (Villages Accounting, Villages Administration, Villages Planning and Engineering)	$14,566	$14,566
Contract Services to VCCDD	12,267	12,267
Rent Expense	4,150	0
Insurance	1,638	0
Organizational Costs	47	0
RAF Fees	16,483	0
Property Tax	273	0
Interest	48,272	0
Total	**$97,696**	**$26,833**

Source: Utility's Cost Justification

In addition, staff recommends removing the 10 percent escalation and the 10 percent contingency adjustments. The Utility used the escalation adjustment to account for inflation of costs between 2017 and 2021. However, SSU has the opportunity to file for an annual price index increase pursuant to Section 367.081(4)(a), F.S.[7] Staff believes the Utility's explanation of the contingency adjustment is duplicative of the escalation adjustment explanation. As such, staff recommends removal of SSU's escalation and contingency adjustments.

Based on the adjustments above, staff recommends a reduction to the Utility's projected management fees of $289,882 for water and $289,882 for wastewater. This results in a total recommended management fee of $86,006 for the water system and $86,006 for the wastewater system.

SSU's annual engineering expenses, $32,146 for water and wastewater each were estimated based on actual costs incurred by CSU during 2016. Similar to the previously discussed expenses, the Utility included an upward adjustment for escalation as well as a contingency. Removal of the escalation and contingency adjustments results in an engineering expense estimate of $21,432 for both water and wastewater. Based on staff's estimate, engineering expenses should be reduced by $10,714.

In total, staff recommends a reduction to O&M expense of $300,596 ($289,882 + $10,714) and $300,596 ($289,882 + $10,714) for water and wastewater, respectively.

[7]Order No. PSC-2017-0480-PAA-WS, issued December 21, 2017, in Docket No. 20170005-WS, *In re: Annual reestablishment of price increase or decrease index of major categories of operating costs incurred by water and wastewater utilities pursuant to section 367.081(4)(a), F.S.*

Depreciation and CIAC Amortization Expense

The Utility reflected depreciation expense, net of CIAC amortization, of $481,464 for water and $803,038 for wastewater. Based on staff's adjustments to rate base, corresponding adjustments should be made to decrease net depreciation by $270,972 and $198,583 for water and wastewater, respectively.

Taxes Other Than Income

In its filing, SSU included RAFs of $149,924 and $198,958 for water and wastewater, respectively. The Utility also included property taxes of $2,368 and $3,452 for water and wastewater, respectively. Staff determined that the Utility incorrectly calculated RAFs. Accordingly, staff recalculated RAFs using 4.5 percent of operating revenues. As such, staff recommends decreasing RAFs for water and wastewater by $20,352 and $45,096, respectively. Corresponding adjustments to decrease property taxes by $465 for water and $456 for wastewater were also made in accordance with staff's adjustment to plant in service as shown in Schedule No. 3-C.

Staff recommends adjusted revenue requirements of $2,286,672 for water and $3,151,727 for wastewater be used to set initial rates for service. The calculation of SSU's projected water and wastewater revenue requirements are shown on Schedule Nos. 3-A and 3-B, respectively. Staff's adjustments are shown on Schedule No. 3-C.

Rates and Rate Structure

SSU structured its proposed rates in accordance with Rule 25-30.033(2), F.A.C., which requires that a base facility and usage rate structure, as defined in Rule 25-30.437(6), F.A.C., be utilized for metered service. The Utility's proposed rates were designed to generate the Utility's requested revenue requirements of $2,879,376 for its water system and $3,419,165 for its wastewater system.

Staff's recommended water rates on Schedule No. 4-A reflect staff's recommended revenue requirement of $2,286,672 for the water system less projected miscellaneous revenues of $39,381. Consistent with the Utility's proposed rate structure, staff recommends a traditional BFC and gallonage charge rate structure with an additional gallonage charge for non-discretionary usage for residential water customers. SSU proposed a discretionary threshold of 3,000 for its residential water customers and staff believes this is reasonable. The Utility proposed allocating 59 percent of the water revenues to the base facility charge (BFC); however, staff recommends allocating 40 percent of water revenues to the BFC because SSU indicated that its customer base would not be seasonal. It has been Commission practice to allocate 40 percent of revenues to the water BFC unless a seasonal customer base or other unique circumstance presents itself.[8]

Additionally, staff's recommended wastewater rates on Schedule No. 4-B reflect staff's recommended revenue requirement of $3,151,727 for the wastewater system less projected

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[8]Order Nos. PSC-2016-0256-PAA-WU, issued June 30, 2016, in Docket No. 20150199-WU, *In re: Application for staff-assisted rate case in Lake County by Raintree Waterworks, Inc.*; 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.*

miscellaneous revenues of $39,381. Staff believes the Utility's proposed wastewater rate structure, which consists of a BFC, gallonage charge, and gallonage cap of 10,000 gallons for residential customers, is reasonable. The Utility proposed allocating 63 percent of wastewater revenues to the BFC. However, it is Commission practice to allocate approximately 50 percent of revenues to the wastewater BFC for the same reasons mentioned above.

The average monthly residential bill for a customer of SSU, based on 3,000 gallons per month would be $27.66 for water and $38.57 for wastewater using staff's recommended rates. Comparatively, the average monthly residential bill for a customer of Central Sumter Utility (CSU), a sister Utility, based on the same usage is $14.99 for water and $30.59 for wastewater.

Conclusion

Based on the above, staff's recommended water and wastewater rates, shown on Schedule Nos. 4-A and 4-B, are reasonable and should be approved. The approved rates should be effective for services rendered or connections made on or after the stamped approval date on the tariff sheets, pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved rates until authorized to change them by the Commission in a subsequent proceeding. A return on equity of 8.74 percent plus or minus 100 basis points should also be approved.

Issue 2: Should the miscellaneous service charges requested by South Sumter Utility Company, LLC be approved?

Recommendation: Yes. The Utility's requested miscellaneous service charges of $35.13 should be approved. The charges should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. SSU should be required to charge the approved charges until authorized to change them by the Commission in a subsequent proceeding. (Friedrich)

Staff Analysis: Section 367.091, F.S., authorizes the Commission to establish miscellaneous service charges. SSU's request was accompanied by its reason for requesting the charges as well as the cost justification required by Section 367.091(6), F.S. The Utility requested initial connection, normal reconnection, violation reconnection and premise visit charges of $35.13 during normal business hours. Additionally, SSU requested that its violation reconnection charge for its wastewater system be actual cost pursuant to Rule 25-30.460(1)(c), F.A.C.

The purpose of these charges is to place the burden for requesting or causing these services on the cost causer rather than the general body of ratepayers. The Utility's requested charges are based on the cost of its contractors to administer and perform miscellaneous services. The VCCDD will perform the administrative labor and CH2M, the Utility's operation and maintenance contractor, will perform the field labor associated with miscellaneous service charges. The Utility requested recovery of $7.53 of administrative labor associated with processing miscellaneous services based on the contractor's hourly salary of $22.60 and its ability to process a miscellaneous service request in approximately 20 minutes ($22.60x20/60). Additionally, SSU requested recovery of $27.60 for the direct expense of the outside contractor performing the field labor. The Utility's cost justification for its requested miscellaneous service charges is shown below in Table 2-1.

Table 2-1
Miscellaneous Service Charges Cost Justification

Field Labor	$27.60
Administrative Labor	$7.53
Total	$35.13

Source: Utility's Cost Justification

Staff compared SSU's requested miscellaneous service charges to those currently in place for its sister Utility, CSU. CSU's charges were based on estimated expenses at the time the original certificate was approved in 2011.[9] Although, CSU's charges were based on estimations and implemented seven years ago, the charges requested by SSU are consistent with CSU's current charges of $21 for normal hours and $42 for after hours. It is also important to note that CSU has not had a proceeding for the Commission to reevaluate these charges since their original implementation. Staff believes the Utility's requested charges are reasonable and should be

[9]Order No. PSC-11-0113-PAA-WS, issued February 11, 2011, in Docket No. 20050192-WS, *In re: Application for certificate to provide water and wastewater service in Sumter County by Central Sumter Utility Company, L.L.C.*

approved. A summary of the Utility's requested miscellaneous service charges are shown below in Table 2-2.

Table 2-2
Miscellaneous Service Charges

Initial Connection Charge	$35.13
Normal Reconnection Charge	$35.13
Violation Reconnection Charge (Water)	$35.13
Violation Reconnection Charge (Wastewater)	Actual Cost
Premises Visit Charge	$35.13

Source: Utility's Cost Justification

Based on the above, the Utility's requested miscellaneous service charges of $35.13 should be approved. The charges should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charges until authorized to change them by the Commission in a subsequent proceeding.

Issue 3: Should the late payment charge requested by South Sumter Utility Company, LLC be approved?

Recommendation: Yes. The Utility's request to implement a $5.50 late payment charge is recommended and should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding. (Friedrich)

Staff Analysis: The Utility requested a $5.50 late payment charge to recover the cost of supplies and labor associated with processing late payment notices. SSU's request for a late payment charge was accompanied by its reason for requesting the charge as well as the cost justification required by Section 367.091, F.S.

Since SSU has not begun to provide its service to customers, staff asked the Utility to provide historical data from its sister Utility, CSU, for staff to consider in its analysis of the Utility's requested late payment charge. The CSU late payment data indicated that approximately 3.4 percent of the CSU customer base is assessed late payment charge each month. This approximation was based on billing data obtained from October 2017 through January 2018.

The Utility requested recovery of $4.59 for the labor associated with processing late payment charges. SSU anticipates its billing specialist will spend approximately 10 minutes per account to research, compile, and produce late notices and the administrative supervisor will spend approximately 3 minutes per account to review the work of the billing specialist as well as prepare reports and identify possible trends. This is consistent with prior Commission decisions where the Commission has allowed 10-15 minutes per account per month for the administrative labor associated with processing delinquent customer accounts.[10] The labor costs include $3.06 ($18.36/6) for the billing specialist and $1.53 ($27.54/18) for the administrative supervisor.

Additionally, SSU requested recovery of the cost of supplies, postage, and RAFs associated with processing delinquent accounts. The Utility's calculation for its requested late payment charge is shown below in Table 3-1.

Table 3-1
Late Payment Charge Cost Justification

Labor	$4.59
Supplies	$0.15
Postage	$0.49
Markup for RAFs	$0.25
Total	$5.48

Source: Utility's Cost Justification

[10]Order Nos. PSC-16-0041-TRF-WU, issued January 25, 2016, in Docket No. 20150215-WU, *In re: Request for approval of tariff amendment to include miscellaneous service charges for the Earlene and Ray Keen Subdivisions, the Ellison Park Subdivision and the Lake Region Paradise Island Subdivision in Polk County, by Keen Sales, Rentals and Utilities, Inc.* and PSC-15-0569-PAA-WS, issued December 16, 2015, in Docket No. 20140239-WS, *In re: Application for staff-assisted rate case in Polk County by Orchid Springs Development Corporation.*

Based on staff's research, over the past seven years the Commission has approved late payment charges ranging from $4.90 to $7.15.[11] The purpose of this charge is not only to provide an incentive for customers to make timely payment, thereby reducing the number of delinquent accounts, but also to place the cost burden of processing delinquent accounts solely upon those who are cost causers. Staff believes the Utility's requested late payment charge is reasonable and should be approved.

Based on the above, SSU's request to implement a $5.50 late payment charge is reasonable and should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding.

[11] Order Nos. PSC-14-0105-TRF-WS, issued February 20, 2014, in Docket No. 130288-WS, *In re: Request for approval of late payment charge in Brevard County by Aquarina Utilities, Inc.;* PSC-15-0535-PAA-WU issued November 19, 2015, in Docket No. 20140217-WU, *In re: Application for staff-assisted rate case in Sumter County by Cedar Acres, Inc.;* and PSC-15-0569-PAA-WS issued December 16, 2015, in Docket No. 20140239-WS, *In re: Application for staff-assisted rate case in Polk County by Orchid Springs Development Corporation.*

Issue 4: Should the Utility's request to implement a backflow prevention assembly testing charge be approved?

Recommendation: Yes. The Utility's requested backflow prevention assembly testing charge for general service customers at actual cost should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. SSU should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding. (Friedrich)

Staff Analysis: The Utility requested a backflow prevention assembly testing charge to recover the costs the Utility would incur for performing annual testing on behalf of non-compliant commercial customers. The Florida Department of Environmental Protection (FDEP) requires customers with cross-connections into the water system to install a backflow prevention assembly on the potable water line. In addition, the FDEP requires that certain backflow prevention assemblies be field-tested at least once a year by a certified contractor. The residential customers of SSU are not required to annually test their backflow prevention assembly devices because the type of assembly they will have, a double check valve, cannot be tested, but FDEP recommends it be replaced every five to ten years pursuant to Rule 62-555.360, F.A.C.

It is the responsibility of the customer to annually test their backflow prevention assembly. The Utility would only administer this charge if a general service customer fails to test their backflow prevention device in accordance with the FDEP requirements. This charge would be imposed after 30 days' notice to the customer and would include an estimate of the amount which will be charged. This noticing period will provide the customer a final opportunity to come into compliance before SSU performs the necessary testing on the customer's behalf. The Utility is requesting this charge at actual cost in order to pass on the amount it will incur from a contractor performing the necessary testing. SSU provided a subcontract agreement to demonstrate the anticipated costs of backflow prevention device testing. Based on the subcontract agreement, the Utility would incur testing costs between $50 and $100 depending on meter size to test the customer's backflow prevention device if the customer is non-compliant with the FDEP requirements.

The Commission previously approved a backflow prevention device testing charge for Black Bear Reserve Corporation (Black Bear).[12] Black Bear's charge is a voluntary testing charge for its residential and general service customers giving customer's an alternative to independently seeking out a certified tester. As mentioned previously, SSU's requested backflow prevention assembly testing charge will only be administered to non-compliant general service customers. The Utility provided related data for its neighboring Utility, North Sumter Utility (NSU). In 2017, NSU had approximately 500 commercial customers with backflow prevention devices and only 36 (7.2 percent) needed to be tested by the Utility. Based on SSU's application, it anticipates it will serve approximately 122 general service customers.

Staff recommends that SSU's request to administer to non-compliant general service customers a backflow prevention assembly testing charge should be approved. This charge may be levied if

[12]Order No. PSC-11-0478-PAA-WU, issued October 24, 2011, in Docket No. 20100085-WU, *In re: Application for certificate to operate water utility in Lake County by Black Bear Reserve Water Corporation.*

circumstances are consistent with those discussed in this issue and will be set forth in the Utility's tariff. The Utility's requested backflow prevention assembly testing charge for general service customers at actual cost should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding.

Issue 5: Should the temporary meter deposit requested by South Sumter Utility Company, LLC be approved?

Recommendation: Yes. The Utility's requested temporary meter deposit for general service customers at actual cost pursuant to Rules 25-30.315 and 25-30.345, F.A.C., is reasonable and should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. SSU should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding. (Friedrich)

Staff Analysis: SSU requested a temporary meter deposit for general service customers consistent with Rules 25-30.315 and 25-30.345, F.A.C., which allows the Utility to charge an applicant a reasonable charge to defray the costs of installing and removing facilities and materials for temporary service. This deposit would be collected from commercial entities requesting a temporary meter for construction activities. Once temporary meter service is terminated, SSU will credit the customer with the reasonable salvage value of the service facilities and materials consistent with Rules 25-30.315 and 25-30.345, F.A.C.

Based on the above, the Utility's requested temporary meter deposit for general service customers at actual cost pursuant to Rules 25-30.315 and 25-30.345, F.A.C., is reasonable and should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding.

Issue 6: Should the investigation of meter tampering charge requested by South Sumter Utility Company, LLC be approved?

Recommendation: Yes. The Utility's requested investigation of meter tampering charge of $35.13 is reasonable and should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. SSU should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding. (Friedrich)

Staff Analysis: Rule 25-30.320(2)(i), F.A.C., provides that a customer's service may be discontinued without notice in the event of tampering with the meter or other facilities furnished or owned by the Utility. In addition, Rule 25-30.320(2)(j), F.A.C., provides that a customer's service may be discontinued in the event of an unauthorized or fraudulent use of service. The rule allows SSU to require the customer to reimburse the Utility for all changes in piping or equipment necessary to eliminate the illegal use and to pay an amount reasonably estimated as the deficiency in revenue resulting from the customer's fraudulent use before restoring service.

SSU requested an investigation of meter tampering charge of $35.13, consistent with its requested miscellaneous service charges (Issue 2). An investigation of meter tampering requires a field representative to go to the customer's premises to inspect the customer's meter and service laterals. Additionally, the administrative employee would set up an appointment time and serve as the liaison between the field representative and the customer.

The Utility's requested charge is consistent with other investigation of meter tampering charges approved by the Commission.[13] Staff recommends SSU's requested charge is reasonable and should be approved. The Utility's requested investigation of meter tampering charge cost justification is shown below in Table 6-1.

Table 6-1
Investigation of Meter Tampering Charge Cost Justification

Field Labor	$27.60
Administrative Labor	$7.53
Total	$35.13

Source: Utility's Cost Justification

Based on the above, SSU's requested investigation of meter tampering charge of $35.13 is reasonable and should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C.

[13]Order Nos. PSC-2017-0367-PAA-WU, issued September 29, 2017, in Docket No. 20160193-WU, *In re: Application for approval of transfer of certain water facilities and Certificate No. 619-W from McLeod Gardens Water Company to McLeod Gardens Utilities, LLC, in Polk County*; PSC-2017-0144-PAA-WU, issued April 27, 2017, in Docket No. 20160143-WU, *In re: Application for staff-assisted rate case in Hardee County by Charlie Creek Utilities, LLC*; and PSC-17-0092-PAA-WU, issued March 13, 2017, in Docket No. 20160144-WU, *In re: Application for transfer of Certificate No. 288-W in Pasco County from Orangeland Water Supply to Orange Land Utilities, LLC.*

The Utility should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding.

Issue 7: Should the collection device cleaning charge requested by South Sumter Utility Company, LLC be approved?

Recommendation: Yes. The Utility's requested collection device cleaning charge for general service customers should be approved. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. SSU should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding. (Friedrich)

Staff Analysis: SSU requested a fats, oil, and grease (FOG) collection device cleaning charge for general service customers to facilitate the Utility's FOG management program. The program is designed to help prevent damage and operational problems in the wastewater collection and treatment system by removing FOG from the wastewater stream prior to it entering the collection system. Once FOG is introduced into the wastewater system, it then cools, solidifies, accumulates and restricts wastewater flow within the pipes. Restaurants are the most common type of general service customer to have higher concentrations of FOG in their discharged wastewater. The Utility indicated that its collection device cleaning charge would only apply to general service customers who fail to perform the required actions after receiving written notice from the Utility with an estimate of potential charges.

All customers with a grease interceptor are required by the Utility to have a quarterly cleaning schedule, provide a cleaning manifest to the Utility, and perform any needed maintenance that has been identified by the customer's grease interceptor cleaning contractor. If a cleaning manifest is not received by the Utility on time or if necessary maintenance has not been performed, a reminder letter will be sent to the customer with an estimate of charges for cleaning the grease interceptor and giving the customer 15 days to come into compliance. If the customer fails to come into compliance by the notified deadline, the Utility will hire a contractor to perform the cleaning and the contractor's cost will be passed through to the general service customer at the actual cost to the Utility.

The Commission has evaluated contamination issues for wastewater Utilities in the past. For KW Resort Utilities, Corp., a monthly lift station cleaning charge was approved for the Monroe County Detention Center.[14] The Commission also approved an increase in contractual services for Harder Hall-Howard, Inc. to address the overflowing grease traps of a restaurant that did not properly maintain its collection devices.[15]

Staff believes the Utility's proposed FOG management program is a reasonable, proactive approach to avoid operational problems in the Utility's collection and treatment facilities. The Utility's request is consistent with Rule 20-30.225(6), F.A.C., which provides that SSU may require that each customer be responsible for cleaning and maintaining sewer laterals to the point of delivery. Therefore, staff recommends the Utility's request to charge a collection device cleaning charge is reasonable and should be approved. This charge may be levied if

[14]Order No. PSC-2017-0091-FOF-SU, issued March 13, 2017, in Docket No. 20150071-SU, *In re: Application for increase in wastewater rates in Monroe County by K W Resort Utilities Corp.*
[15]Order No. PSC-02-0382-PAA-SU, issued March 21, 2002, in Docket No. 20010828-SU, *In re: Application for staff-assisted rate case in Highlands County by Harder Hall-Howard, Inc.*

circumstances are consistent with those discussed in this issue and will be set forth in the Utility's tariff. The approved charge should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charge until authorized to change it by the Commission in a subsequent proceeding.

Issue 8: Should South Sumter Utility Company, LLC be authorized to collect Non-Sufficient Funds (NSF) Charges?

Recommendation: Yes. SSU should be authorized to collect NSF charges pursuant to Section 68.065 F.S. The approved charges should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charges until authorized to change them by the Commission in a subsequent proceeding. (Friedrich)

Staff Analysis: Section 367.091, F.S., requires rates, charges, and customer service policies to be approved by the Commission. The Commission has authority to establish, increase, or change a rate or charge. Staff believes that SSU should be authorized to collect NSF charges consistent with Section 68.065, F.S., which allows for the assessment of charges for the collection of worthless checks, drafts, or orders of payment. As currently set forth in Section 68.065(2), F.S., the following NSF charges may be assessed:

1. $25, if the face value does not exceed $50,
2. $30, if the face value exceeds $50 but does not exceed $300,
3. $40, if the face value exceeds $300,
4. or five percent of the face amount of the check, whichever is greater.

Approval of NSF charges is consistent with prior Commission decisions.[16] Furthermore, NSF charges places the cost on the cost-causer, rather than requiring that the costs associated with the return of the NSF checks be spread across the general body of ratepayers. As such, SSU should be authorized to collect NSF charges pursuant to Section 68.065 F.S. The approved charges should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charges until authorized to change them by the Commission in a subsequent proceeding.

[16]Order Nos. PSC-14-0198-TRF-SU, issued May 2, 2014, in Docket No. 140030-SU, *In re: Request for approval to amend Miscellaneous Service charges to include all NSF charges by Environmental Protection Systems of Pine Island, Inc.* and PSC-13-0646-PAA-WU, issued December 5, 2013, in Docket No. 130025-WU, *In re: Application for increase in water rates in Highlands County by Placid Lakes Utilities, Inc.*

Issue 9: Should the Utility's requested initial customer deposits be approved?

Recommendation: No. The appropriate initial customer deposits are $41.28 for water and $50.34 for wastewater service for the residential 5/8" x 3/4" meter size. The initial customer deposit for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill. The approved customer deposits should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to collect the approved deposits until authorized to change them by the Commission in a subsequent proceeding. (Friedrich)

Staff Analysis: Rule 25-30.311, F.A.C., contains criteria for collecting, administering, and refunding customer deposits. Rule 25-30.311(1), F.A.C., requires that each company's tariff shall contain its specific criteria for determining the amount of initial deposits. The Utility requested initial customer deposits of $67.40 for water and $103.00 for wastewater for the residential 5/8" x 3/4" meter sizes and two times the average estimated monthly bill for all others. Customer deposits are designed to minimize the exposure of bad debt expense for the Utility and, ultimately, the general body of rate payers. In addition, collection of customer deposits is consistent with one of the fundamental principles of rate making—ensuring that the cost of providing service is recovered from the cost causer.

Rule 25-30.311(7), F.A.C., authorizes utilities to collect new or additional deposits from existing customers not to exceed an amount equal to the average actual charge for water and/or wastewater service for two billing periods for the 12-month period immediately prior to the date of notice. The two billing periods reflect the lag time between the customer's usage and the Utility's collection of the revenues associated with that usage. Commission practice has been to set initial customer deposits equal to two months bills based on the average consumption for a 12-month period for each class of customers. Staff reviewed the projected billing data provided in SSU's application and determined that the anticipated average residential usage will be approximately 2,616 gallons per month for both water and wastewater. Consequently, the average residential monthly bill will be approximately $20.64 for water and $25.17 for wastewater service, based on staff's recommended rates.

Based on the above, the appropriate initial customer deposits are $41.28 for water and $50.34 for wastewater service for the residential 5/8" x 3/4" meter size. The initial customer deposit for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill. The approved customer deposits should be effective for service rendered on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to collect the approved deposits until authorized to change them by the Commission in a subsequent proceeding.

Issue 10: What are the appropriate service availability charges for South Sumter Utility Company, LLC?

Recommendation: The appropriate service availability charges are a meter installation charge of $402 for a 5/8" x 3/4" meter and a main extension charge of $1,916 per ERC for the Utility's water system. Additionally, a main extension charge of $2,610 per ERC and a plant capacity charge of $450 per ERC for the Utility's wastewater system should be approved. The recommended main extension and plant capacity charges should be based on an estimated 86 gallons per day (gpd) of water demand. The approved charges should be effective for connections made on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. The Utility should be required to charge the approved charges until authorized to change them by the Commission in a subsequent proceeding. (Friedrich)

Staff Analysis: SSU requested a meter installation charge of $402 for 5/8" x 3/4" meters and actual cost for all other meter sizes, and a main extension charge of $1,315 per ERC and a plant capacity charge of $639 per ERC for its water system. Additionally, the Utility requested a main extension charge of $1,241 per ERC and a plant capacity charge of $1,010 per ERC for its wastewater system. According to the Utility, the requested service availability charges are based on the projected cost of the water and wastewater systems and the anticipated capacity of 8,542 ERCs. In addition, the requested charges reflect an allocation based on the costs of the distribution and collection systems. SSU's projected distribution and collection systems costs reflect two-thirds of the total costs of the projected plant; therefore, the requested main extension charges reflect two-thirds of the requested service availability charges. Similarly, the requested plant capacity charges reflect one-third of the requested service availability charges. Further, according to the Utility, the requested charges are in compliance with Rule 25-30.580, F.A.C., in that at design capacity the CIAC will not be in excess of 75 percent, and will not be less than the percentage of facilities and plant represented by the distribution and collection systems.

Rule 25-30.580(1)(a), F.A.C., provides that the maximum amount of CIAC, net of amortization, should not exceed 75 percent of the total original cost, net of accumulated depreciation, of the Utility's facilities and plant when the facilities and plant are at their design capacity. The maximum guideline is designed to ensure that the Utility retains an investment in the system. Rule 25-30.580(1)(b), F.A.C., provides that the minimum amount of CIAC should not be less than the percentage of such facilities and plant that is represented by the distribution and collection systems.

Meter Installation Charges

SSU is requesting approval of a meter installation charge of $402 for 5/8" x 3/4" meters. All other meter sizes will be installed at the Utility's actual cost. The Utility's proposed meter installation charge of $402 is based on the estimated cost to install water meters and the required backflow prevention device for the 5/8" x 3/4" meter size. Staff recommends the meter installation charges are reasonable and should be approved.

Main Extension Charges

Based on staff's recommended adjustments to SSU's projected UPIS costs, the projected cost of the water and wastewater systems are $22,267,563 and $36,783,852. Typically the Commission approves main extension charges based on the average cost per ERC of the distribution and collection systems and the anticipated capacity. Therefore, staff recommends main extension charges of $1,916 for water and $2,610 for wastewater.

Plant Capacity Charges

As mentioned above, Rule 25-30.580, F.A.C., provides minimum and maximum guidelines for designing service availability charges. Since the value of the distribution system represents such a significant percentage of the water system (73 percent), even a minimal additional plant capacity charge would result in an overall contribution level in excess of 75 percent at design capacity. This differs from the Utility's calculations for its proposed service availability charges because staff's recommended rate base reflects a significant reduction in the projected costs of the water system. Additionally, staff's recommended main extension charge reflects the average projected cost per ERC rather than an allocation of costs between the main extension and plant capacity charges. Therefore, staff recommends a plant capacity charge for water should not be approved.

Based on staff's recommended main extension charge for wastewater, staff recommends a plant capacity charge of $450 per ERC for wastewater, which would result in a projected contribution level of approximately 61 percent at design capacity. Staff believes this is consistent with Rule 25-30.580, F.A.C., and will allow SSU to maintain an appropriate investment in its system. Table 10-1 below displays the Utility's proposed and staff's recommended service availability charges for its water and wastewater systems.

Table 10-1
Service Availability Charges

	Utility Proposed		Staff Recommended	
Charge	Water	Wastewater	Water	Wastewater
Meter Installation Charge	$402	N/A	$402	N/A
Main Extension Charge ERC = 86 gpd	$1,315	$1,241	$1,916	$2,610
Plant Capacity Charge ERC = 86 gpd	$639	$1,010	N/A	$450

Source: Utility's Cost Justification

Based on the above, the appropriate service availability charges are a meter installation charge of $402 for a 5/8" x 3/4" meter and a main extension charge of $1,916 per ERC for the Utility's water system. Additionally, a main extension charge of $2,610 per ERC and a plant capacity charge of $450 per ERC for the Utility's wastewater system. The recommended main extension and plant capacity charges should be based on an estimated 86 gpd of water demand. The approved charges should be effective for connections made on or after the stamped approval date on the tariff pursuant to Rule 25-30.475, F.A.C. SSU should be required to charge the approved charges until authorized to change them by the Commission in a subsequent proceeding.

Issue 11: Should this docket be closed?

Recommendation: No. 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. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff. Once these actions are complete, this docket should be closed administratively. (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. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff. Once these actions are complete, this docket should be closed administratively.

South Sumter **Schedule of Water Rate Base** **Projected at 80% Design Capacity**				**Schedule No. 1-A** **20160220-WS**
	Description	**Test Year Per Utility**	**Staff Adjust-ments**	**Staff Adjusted Test Year**
1	Plant in Service	$30,098,803	($7,831,240)	$22,267,563
2	Land and Land Rights	0	0	0
3	Accumulated Depreciation	(2,237,520)	947,770	(1,289,750)
4	CIAC	(15,264,648)	2,171,470	(13,093,178)
5	Amortization of CIAC	617,237	(12,667)	604,570
6	Working Capital Allowance	191,984	(37,575)	154,409
7	**Rate Base**	$13,405,856	($4,762,241)	$8,643,615

South Sumter Schedule of Wastewater Rate Base Projected at 80% Design Capacity				Schedule No. 1-B 20160220-WS
	Description	Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year
1	Plant in Service	$41,797,661	($5,013,811)	$36,783,851
2	Land and Land Rights	0	0	0
3	Accumulated Depreciation	(3,052,616)	56,898	(2,995,718)
4	CIAC	(17,584,812)	(3,326,003)	(20,910,815)
5	Amortization of CIAC	711,054	343,628	1,054,682
6	Working Capital Allowance	188,054	(37,575)	150,479
7	**Rate Base**	$22,059,341	($7,976,863)	$14,082,478

South Sumter
Adjustments to Rate Base
Projected at 80% Design Capacity

Schedule No. 1-C
20160220-WS

Explanation	Water	Wastewater
Plant In Service		
To reflect 80% design capacity.	($7,831,240)	($5,013,811)
Accumulated Depreciation		
To reflect appropriate level of accumulated depreciation.	$947,770	$56,898
CIAC		
To reflect 80% design capacity.	$2,171,470	($3,326,003)
Accumulated Amortization of CIAC		
To reflect appropriate level of accumulated amortization of CIAC.	($12,667)	$343,628
Working Capital		
To reflect 1/8 of O&M expense.	($37,575)	($37,575)

South Sumter
Capital Structure
Projected at 80% Design Capacity

Schedule No. 2
20160220-WS

	Description	Total Capital	Specific Adjust-ments	Subtotal Adjusted Capital	Prorata Adjust-ments	Capital Reconciled to Rate Base	Ratio	Cost Rate	Weighted Cost
Per Utility									
1	Long-term Debt	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%
2	Short-term Debt	0	0	0	0	0	0.00%	0.00%	0.00%
3	Preferred Stock	0	0	0	0	0	0.00%	0.00%	0.00%
4	Common Equity	34,938,810	0	34,938,810	0	34,938,810	98.52%	8.76%	8.63%
5	Customer Deposits	526,386	0	526,386	0	526,386	1.48%	2.00%	0.03%
6	Tax Credits-Zero Cost	0	0	0	0	0	0.00%	0.00%	0.00%
7	Deferred Income Taxes	0	0	0	0	0	0.00%	0.00%	0.00%
8	**Total Capital**	$35,465,196	$0	$35,465,196	$0	$35,465,196	100.00%		8.66%
Per Staff									
9	Long-term Debt	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%
10	Short-term Debt	0	0	0	0	0	0.00%	0.00%	0.00%
11	Preferred Stock	0	0	0	0	0	0.00%	0.00%	0.00%
12	Common Equity	34,938,810	0	34,938,810	(13,009,089)	21,929,721	96.50%	8.74%	8.43%
13	Customer Deposits	526,386	269,987	796,373	0	796,373	3.50%	2.00%	0.07%
14	Tax Credits-Zero Cost	0	0	0	0	0	0.00%	0.00%	0.00%
15	Deferred Income Taxes	0	0	0	0	0	0.00%	0.00%	0.00%
16	**Total Capital**	$35,465,196	$269,987	$35,735,183	($13,009,089)	$22,726,094	100.00%		8.50%

	LOW	HIGH
RETURN ON EQUITY	7.74%	9.74%
OVERALL RATE OF RETURN	7.54%	9.47%

South Sumter
Statement of Water Operations
Projected at 80% Design Capacity

Schedule No. 3-A
20160220-WS

	Description	Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year	Revenue Increase	Revenue Requirement
1	**Operating Revenues**	$2,879,376	$0	$2,879,376	($592,704)	$2,286,672
					-20.58%	
	Operating Expenses					
2	Operation & Maintenance	$1,535,871	($300,596)	$1,235,275		$1,235,275
3	Depreciation	481,464	(270,972)	210,492		210,492
4	Amortization	1,066	0	1,066		1,066
5	Taxes Other Than Income	152,291	(20,817)	131,474	(26,672)	104,802
6	Income Taxes	0	0	0	0	0
7	**Total Operating Expense**	2,170,692	(592,386)	1,578,306	(26,672)	1,551,635
8	**Operating Income**	$708,684	$592,386	$1,31,070	($566,032)	$735,037
9	**Rate Base**	$13,405,856		$8,643,615		$8,643,615
10	**Rate of Return**	5.29%		15.05%		8.50%

South Sumter | **Schedule No. 3-B**
Statement of Wastewater Operations | **20160220-WS**
Projected at 80% Design Capacity

	Description	Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year	Revenue Increase	Revenue Requirement
1	**Operating Revenues**	$3,419,165	$0	$3,419,165	($267,438)	$3,151,727
					-7.82%	
	Operating Expenses					
2	Operation & Maintenance	$1,504,430	($300,596)	$1,203,834		$1,203,834
3	Depreciation	803,038	(198,583)	604,45		604,455
4	Amortization	1,066	0	1,066		1,066
5	Taxes Other Than Income	202,410	(45,551)	156,859	(12,035)	144,824
6	Income Taxes	0	0	0	0	0
7	**Total Operating Expense**	2,510,944	(544,730)	1,966,214	(12,035)	1,954,179
8	**Operating Income**	$908,221	$544,730	$1,452,952	($255,404)	$1,197,548
9	**Rate Base**	$22,059,341		$14,082,478		$14,082,478
10	**Rate of Return**	4.12%		10.32%		8.50%

South Sumter
Adjustments to Operating Income
Projected at 80% Design Capacity

Schedule No. 3-C
20160220-WS

	Explanation	Water	Wastewater
	Operation and Maintenance Expense		
	To adjust contractual services.	($300,596)	($300,596)
	Depreciation Expense - Net		
	To reflect appropriate level of net depreciation expense.	($270,972)	($198,583)
	Taxes Other Than Income		
1	To reflect appropriate level of property tax.	($465)	($456)
2	To reflect appropriate level of RAFs.	(20,352)	(45,096)
	Total	($20,817)	($45,551)

SOUTH SUMTER UTILITY COMPANY, LLC | **SCHEDULE NO. 4-A**
MONTHLY WATER RATES | **DOCKET NO. 20160220-WS**

	UTILITY REQUESTED RATES	STAFF RECOMMENDED RATES
Residential and General Service		
Base Facility Charge by Meter Size		
5/8" X 3/4"	$20.30	$10.96
3/4"	$30.45	$16.44
1"	$50.75	$27.41
1-1/2" Turbine	$101.50	$54.81
2" Turbine	$162.40	$87.70
3" Turbine	$355.25	$191.85
Charge per 1,000 gallons- Residential Service		
0-3,000 gallons	$4.75	$5.57
Over 3,000 gallons	$7.08	$6.96
Charge per 1,000 gallons- General Service	$4.46	$5.75
Typical Residential 5/8" x 3/4" Meter Bill Comparison		
3,000 Gallons	$34.55	$27.66
6,000 Gallons	$55.79	$48.53
10,000 Gallons	$84.11	$76.36

SOUTH SUMTER UTILITY COMPANY, LLC | **SCHEDULE NO. 4-B**
MONTHLY WASTEWATER RATES | **DOCKET NO. 20160220-WS**

	UTILITY REQUESTED RATES	STAFF RECOMMENDED RATES
Residential Service		
Base Facility Charge- All Meter Sizes	$26.00	$18.98
Charge per 1,000 gallons- Residential	$5.33	$6.53
10,000 gallon cap		
General Service		
Base Facility Charge by Meter Size		
5/8" X 3/4"	$26.00	$18.98
3/4"	$39.00	$28.47
1"	$65.00	$47.45
1-1/2" Turbine	$130.00	$94.89
2" Turbine	$208.00	$151.82
3" Turbine	$455.00	$332.12
Charge per 1,000 gallons - General Service	$5.56	$7.83
Typical Residential 5/8" x 3/4" Meter Bill Comparison		
3,000 Gallons	$41.99	$38.57
6,000 Gallons	$57.98	$58.16
10,000 Gallons	$79.30	$84.28

Item 3

FILED 4/26/2018
DOCUMENT NO. 03223-2018
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: April 26, 2018

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (M. Watts, Thompson)
Office of the General Counsel (Mapp) KRM

RE: Docket No. 20170142-SU – Application for amendment of Certificate No. 137-S for extension of wastewater service territory in Brevard County, by Merritt Island Utility Company, Inc.

AGENDA: 05/08/18 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On June 12, 2017, Merritt Island Utility Company, Inc. (MIU or Utility) filed an application with the Florida Public Service Commission (Commission) to amend Certificate No. 137-S to add territory in Brevard County. When MIU acquired the wastewater system and Certificate No. 137-S in 2017,[1] the previous owner was serving the territory requested in the instant docket.

Mobile Home Investors, Inc. was initially granted a certificate to operate a wastewater system in existence in 1974.[2] In 1976, the Florida Public Service Commission (Commission) approved the

[1]Order No. PSC-2017-0366-PAA-SU, issued September 27, 2017, in Docket No. 20170018-SU, *In re: Application to transfer wastewater system and Certificate No. 137-S in Brevard County from Colony Park Development Utilities, LLC to Merritt Island Utility Company, Inc.*

[2]Order No. 6365, issued December 2, 1974, in Docket No. 73391-S, *In re: Application of MOBILE HOME INVESTORS, INC., for a certificate to operate an existing sewer utility in Brevard County, Florida.*

transfer of the wastewater system and Certificate No. 137-S to Colony Park Utilities, Inc.[3] In 2003[4] and 2007,[5] the Utility was granted transfers of majority organizational control, and in 2014 the wastewater system and Certificate No. 137-S were transferred to Colony Park Development Utilities, LLC (CPDU).[6] In each of these transactions, the sale included both the Utility and the Colony Park mobile home park.

CPDU subsequently sold the mobile home park and the wastewater system to Colony Waste Services, LLC (CWS) in 2016. CPDU and CWS did not file an application for transfer of the system and wastewater certificate at that time. CWS did not want the wastewater system, and sold it to MIU, who then filed an application for transfer.[7] During the pendency of Docket No. 20170018-SU, staff and MIU determined that the wastewater treatment plant was serving customers outside the certificated territory. This recommendation addresses the Utility's request to extend its wastewater service territory. The Commission has jurisdiction pursuant to Section 367.045, Florida Statutes (F.S.).

[3]Order No. 7296, issued June 28, 1976, in Docket No. 750664-S, *In re: Application of MOBILE HOME INVESTORS, INC., and COLONY PARK UTILITIES, INC. for approval of the transfer of assets and Certificate No. 137-S from the former to the latter. (Section 367.071, Florida Statutes).*
[4]Order No. PSC-03-0320-FOF-SU, issued March 6, 2003, in Docket No. 020930-SU, *In re: Application for transfer of majority organizational control of Colony Park Utilities, Inc. holder of Certificate No. 137-S in Brevard County, from Robert Warren, Lenore Warren, William Warren, and Carol Kendall to Eileen Rogow, Arthur Rogow, and Philip Young.*
[5]Order No. PSC-07-0420-FOF-SU issued May 14, 2007, in Docket No. 060636-SU, *In re: Application for transfer of majority organizational control of Colony Park Utilities, Inc., holder of Certificate No. 137-S in Brevard County from Eileen Rogow to Michael Abramowitz.*
[6]Order No. PSC-14-0673-PAA-SU, issued December 5, 2014, in Docket No. 120285-SU, *In re: Application to transfer wastewater facilities and Certificate No. 137-S in Brevard County from Colony Park Utilities, Inc. to Colony Park Development Utilities, LLC.*
[7]Order No. PSC-2017-0366-PAA-SU, issued September 27, 2017, in Docket No. 20170018-SU, *In re: Application to transfer wastewater system and Certificate No. 137-S in Brevard County from Colony Park Development Utilities, LLC to Merritt Island Utility Company, Inc.*

Discussion of Issues

Issue 1: Should the Commission approve Merritt Island Utility Company, Inc.'s application for amendment of Certificate No. 137-S to extend its wastewater territory in Brevard County?

Recommendation: Yes. It is in the public interest to amend Certificate No. 137-S to include the territory as described in Attachment A, effective the date of the Commission's vote. The resultant order should serve as MIU's amended certificate and should be retained by the Utility. The Utility should continue charging the customers in the territory added herein the rates and charges contained in its current tariff until a change is authorized by the Commission in a subsequent proceeding. (M. Watts)

Staff Analysis: The Utility's application to amend its authorized service territory is in compliance with the governing statute, Section 367.045, F.S., and Rule 25-30.036, Florida Administrative Code (F.A.C.), Application for Amendment to Certificate of Authorization to Extend or Delete Service Area. The application contains proof of compliance with the noticing provisions set forth in Rule 25-30.030, F.A.C., Notice of Application and of Customer Meeting. No objections to the application have been received and the time for filing such has expired.

MIU provided adequate service territory maps and territory descriptions to the Commission. According to the application, the provision of wastewater services in the proposed service territory is consistent with the North Merritt Island Small Area Plan Study. As stated in the case background, when MIU acquired the Utility, the proposed additional service territory, serving approximately 75 equivalent residential connections, was already being served by the previous owner. Based on a review of the annual reports filed for the system, it appears that wastewater service was extended to the additional territory in the 1995 through 1996 time frame by Colony Park Utilities, Inc., who held Certificate No. 137-S from 1976 to 2014.

The Utility stated in its application that the existing customers (including those in the proposed extended service area) are served by a 0.070 million gallon per day treatment plant permitted on an annual average daily flow basis from the Florida Department of Environmental Protection (DEP). The system is built out and existing collection lines are sized to serve the customers currently being served.

The Utility was granted a rate increase in 2008,[8] and at that time, the Commission found the overall quality of service of the Utility to be satisfactory and there currently appear to be no outstanding Consent Orders or Notices of Violation from the DEP. Based upon staff's review of the financial information provided in this docket, the Utility's financial ability to operate a utility has not diminished since the Utility's 2008 rate case. The Utility has filed its 2017 Annual Report and is current with the payment of its 2017 Regulatory Assessment Fees (RAFs). Based on the foregoing analysis, staff recommends that MIU has the financial and technical ability to service the amended territory.

[8]Order No. PSC-08-0760-PAA-SU, issued November 17, 2008, in Docket No. 080104-SU, *In re: Application for staff-assisted rate case in Brevard County by Colony Park Utilities, Inc.*

Conclusion

Based on the information above, staff recommends it is in the public interest to amend Certificate No. 137-S to include the territory as described in Attachment A, effective the date of the Commission's vote. The resultant order should serve as MIU's amended certificate and should be retained by the Utility. The Utility should continue charging the customers in the territory added herein the rates and charges contained in its current tariffs until a change is authorized by the Commission in a subsequent proceeding.

Issue 2: Should Merritt Island Utility Company, Inc. be required to show cause why it should not be fined for an apparent violation of Section 367.045(2), F.S., for serving customers outside of its Commission approved territory?

Recommendation: No. Staff recommends that the Utility's apparent violation of Section 367.045(2), F.S., does not rise to the level which warrants the initiation of a show cause proceeding. Therefore, MIU should not be required to show cause for serving customers outside of its Commission approved territory. (Mapp)

Staff Analysis: Pursuant to Section 367.045(2), F.S., a utility may not delete or extend its service outside the area described in its certificate of authorization until it has obtained an amended certificate of authorization from the Commission. Section 367.161(1), F.S., authorizes the Commission to assess a penalty of not more than $5,000 for each offense, if a utility is found to have knowingly refused to comply with, or to have willfully violated, any provision of Chapter 367, F.S. By serving customers outside of its certificated territory without obtaining an amended certificate of authorization, the Utility's act was "willful" within the meaning of Section 367.161, F.S. Utilities are charged with the knowledge of the Commission's statutes and rules. Thus, any intentional act, such as MIU providing wastewater service beyond the boundaries of Certificate No. 137-S, without first obtaining a certificate of authorization from the Commission, would meet the standard for a "willful violation" of Section 357.161(1), F.S.

In Order No. 24306, issued April 1, 1991, in Docket No. 890216-TL, <u>In Re: Investigation Into The Proper Application of Rule 25-14.003, Florida Administrative Code, Relating To Tax Savings Refund For 1988 and 1989 For GTE Florida, Inc.</u>, the Commission, having found that the Company had not intended to violate the rule, nevertheless found it appropriate to order it to show cause why it should not be fined, stating that "[i]n our view, 'willful' implies an intent to do an act, and this is distinct from an intent to violate a statute or rule"; <u>see also</u> Order No. PSC-99-2390-FOF-WU, Issued on December 7, 1999, in Docket No. 980543-WU, <u>In re: Application for amendment of Certificate No. 363-W to add territory in Marion County by Sunshine Utilities of Central Florida, Inc.</u>, (finding that the utility's apparent violation of Section 367.045, F.S., did not warrant the initiation of a show cause proceeding). Additionally, "it is a common maxim, familiar to all minds that 'ignorance of the law' will not excuse any person, either civilly or criminally." <u>Barlow v. United States</u>, 32 U.S. 404,411 (1833).

Although MIU's failure to obtain an amended certificate of authorization from the Commission prior to serving outside of its certificated area is an apparent violation of Section 367.045(2), F.S., there are mitigating circumstances. When MIU acquired the Utility, the proposed additional service territory, approximately 75 ERCs, was already being served by the previous owner. During the evaluation of MIU's transfer application, Docket No. 20170018-SU, when it was discovered that the Utility was serving outside of its certificated territory, MIU immediately filed the instant application to correct that oversight by requesting the territory be added to its service area. Additionally, the Utility has paid RAFs on these customers.

Based on the foregoing, staff recommends that the Utility's apparent violation of Section 367.045(2), F.S., does not rise to the level which warrants the initiation of a show cause proceeding. Therefore, Merritt Island Utility Company, Inc. should not be required to show cause for failure to obtain an amended certificate of authorization prior to serving outside of its certificated territory.

Issue 3: Should this docket be closed?

Recommendation: If the Commission approves staff's recommendations in Issues 1 and 2, no further action will be necessary, and this docket should be closed upon issuance of the order. (Mapp)

Staff Analysis: If the Commission approves staff's recommendations in Issues 1 and 2, no further action will be necessary, and this docket should be closed upon issuance of the order.

Merritt Island Utility Company, Inc.

Brevard County

Description of Wastewater Territory

TERRITORY TO BE ADDED:

Colony Park North - Unit 3

A portion of the South ½ of the S.E. ¼ of Section 15, Township 23 S, Range 36 E, Brevard County, Florida, being more particularly described as follows: Commence at the N.E. Corner of the South ½ of the S.E. ¼ of aforesaid Section 15; thence S 88° 09' 37" W along the north line of the South ½ of the S.E. ¼ of said Section 15, a distance of 1,547.55 feet to the Point of Beginning of the lands herein described; thence continue S 88° 09' 37" W along the north line of the S.E. ¼ of said Section 15, a distance of 1,085.06 feet to the N.W. corner of the S ½ of the S.E. ¼ of said Section 15; thence S 00° 41' 31" E along the west line of the S.E. ¼ of said Section 15, a distance of 239.77 feet; thence N 89° 18' 29" E a distance of 205.00 feet; thence S 00° 41' 31" E a distance of 66.18 feet; thence N 88° 09' 37" E a distance of 450.09 feet; thence N 88° 09' 42" E a distance of 50.01 feet; thence N 88°09' 37" E a distance of 242.01 feet; thence S 84° 54' 05" E a distance of 498.64 feet; thence N 89° 20' 56" E a distance of 321.53 feet; thence N 00° 39' 04" W along the west line of Colony Park North Unit 2 as recorded in the Plat Book 24, Page 74, Brevard County Public Records, and its extension, a distance of 105.00 feet; thence S 89° 20' 56" W along the west line of said Colony Park North Unit No. 2, a distance of 5.00 feet; thence N. 00°39'04" W. along the west line of said Colony Park North Unit No. 2, and it's extension, a distance of 231.88 feet; thence S 89° 00' 32" W a distance of 675.01 feet; thence N 00° 39' 04" W a distance of 30.00 feet to the Point of Beginning. Containing 12.48 acres more or less.

Mission Acres

The South ½ of the SW ¼ of the SW ¼ of Section 14, Township 23 South, Range 36 East, lying West of now existing County Road, being more particularly described as follows: Commence from The Point of Beginning being the Southwest corner of Section 14, Township 23 South, range 36 East; thence N 89° 54' 47" E along the South line of said Section 14 for a distance of 1,163.12 feet to a point on the Westerly right of way line of McGruder Road; thence N 33°56' 42" E along said Westerly right of way for a distance of 286.74 feet to a point on the East line of the South ½ of the SW ¼ of the SW ¼ of said Section 14; thence go Northerly along the East line of the South ½ of the SW ¼ of the SW ¼ of said Section 14, N 0°06'25" E for a distance of 91.67 feet to a point being the Northeast corner of the South ½ of the SW ¼ of the SW ¼ of said Section 14; thence run along the North line of the South ½ of the SW ¼ of the SW ¼ , West for a distance of 1,323.41 feet to a point being the Northwest corner of the South ½ of the SW ¼ of the SW ¼ of said Section 14; thence run Southerly along the West line of said Section 14, S0°0'3.05"E for a distance of 330.00 feet to the Point of Beginning, said parcel contains 9.580 acres more or less; less and except the West 30.00 feet thereof.

COMPOSITE WASTEWATER TERRITORY

In Township 23 South, Range 36 East, Brevard County, Florida

Section 14 & 15

Begin at the Southwest corner of said Section 14, Township 23 South. Range 36 East, which is also the Point of Beginning; thence run North 89° 54' 47" East along the South line of said section 14 for a distance of 1163.12 feet to a point on the Westerly right of way line of a County Road; thence North 33° 56' 42" East along said Westerly right of way line for a distance of 286.74 feet to a point on the East line of the South ½ of the SW ¼ of the SW ¼ of said section 14; thence go North 0° 06' 25" East for a distance of 91.67 feet; thence run North 75° 28' 48" West for a distance of 25.08 feet; thence North 2° 00' 24" West for a distance of 985.22 feet; thence South 89° 11' 06" West for a distance of 569.57 feet; thence South 0°·48' 54" East for a distance of 10 feet; thence South 87° 05' 16" West a distance of 710.58 feet; thence South 0°·39' 04" East, 30.99 feet; thence North 89° 35' 04" West, 477.03 feet; thence South 0°·38' 31" West, 25 feet; thence South 68° 21' 32" West, 84.30 feet; thence South 76° 38' 12" West, 83.63 feet; thence South 89° 20' 56" West, 234.00 feet; thence North 0° 56' 37" West, 81.56 feet; thence South 89° 00' 32" West, 675.01 feet; thence North 00° 39' 04" West, 30.00 feet; thence South 88° 09 '37" West, 1,085.06 feet; thence South 0° 41' 31" East, 239.77 feet; thence North 89° 18' 29" East, 205.00 feet; thence South 0° 41' 31" East, 66.18 feet; thence North 88° 09' 37" East, 742.10 feet; thence South 84° 34' 05" East, 498.64 feet; thence North 89° 20' 56" East, 319.55 feet; thence South 00° 39' 04" West, 384.45 feet; thence South 87° 45' 45" West, 358.30 feet; thence South 02° 14' 15" East, 150.00 feet to a point on the South boundary of St. Charles Avenue; thence Westerly 30 feet more or less; thence South 02° 14' 15" East, 400.00 feet; thence North 88° 7' 24" East, 1,251.15 feet, more or less to the Point of Beginning.

FLORIDA PUBLIC SERVICE COMMISSION

Authorizes

Merritt Island Utility Company, Inc.

Pursuant to

Certificate Number 137-S

to provide wastewater service in Brevard 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
6365	12/02/1974	73391-S	Original Certificate
7296	06/28/1976	750664-S	Transfer
PSC-03-0320-FOF-SU	03/06/2003	020930-SU	Transfer of Majority Organizational Control
PSC-07-0420-FOF-SU	05/14/2007	060636-SU	Transfer of Majority Organizational Control
PSC-14-0673-PAA-SU	12/05/2014	120285-SU	Transfer
PSC-2017-0366-PAA-SU	09/27/2017	20170018-SU	Transfer
• -	*	20170142-SU	Amendment

Item 4

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: April 26, 2018

TO: Docket No. 20170166-WS - Application for limited proceeding rate increase in Orange County by Pluris Wedgefield, Inc.

FROM: Carlotta S. Stauffer, Commission Clerk, Office of Commission Clerk

RE: Rescheduled Commission Conference Agenda Item

Staff's memorandum assigned DN 02797-2018 was filed on April 6, 2018, for the April 20, 2018 Commission Conference. As the vote sheet for the April 20, 2018 Commission Conference reflects, this item was deferred to the May 8, 2018 Commission Conference. This item has been placed on the agenda for the May 8, 2018 Commission Conference, and staff's previously filed memorandum is attached.

/css

Attachment

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: April 6, 2018

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (P. Buys, Graves, King) PDB RG TB MC CRBB ALM
Division of Accounting and Finance (D. Buys, Smith II) AS DBB
Division of Economics (Friedrich, Hudson) SH MF
Office of the General Counsel (Janjic, Crawford)

RE: Docket No. 20170166-WS-Application for limited proceeding rate increase in Orange County by Pluris Wedgefield, Inc.

AGENDA: 04/20/18 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Polmann

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

Pluris Wedgefield, Inc. (Pluris or Utility) is a Class B utility providing service to approximately 1,615 water and wastewater customers in Orange County. Pluris also provides service to approximately 33 irrigation customers. Water and wastewater rates were last established for this Utility in 2013.[1]

On July 28, 2017, Pluris filed a request for a limited proceeding increase in water and wastewater rates. In its application, Pluris requested recovery of costs associated with four projects. The

[1]Order No. PSC-13-0187-PAA-WS, issued May 2, 2013, in Docket No. 20120152-WS, *In re: Application for increase in water and wastewater rates in Orange County by Pluris Wedgefield, Inc.*

Utility requested final revenue increases of $194,159 (13.8 percent) for water and $57,545 (6.0 percent) for wastewater.[2]

Pursuant to Rule 25-30.445, Florida Administrative Code (F.A.C.), the Utility provided a copy of all customer complaints that it received regarding Florida Department of Environmental Protection (DEP) secondary water quality standards during the past five years and a copy of the Utility's most recent secondary water quality standards test results.[3] Pluris additionally provided its most recent chemical analysis in which it tested primary water standards.[4] The documentation provided by Pluris indicates that the Utility is currently passing primary and secondary standards. From 2013 to 2017, the Florida Public Service Commission (Commission) received eighteen customer inquires concerning the Utility's water quality, which were sent to the DEP and the Utility.

A customer meeting was held November 2, 2017, in Orlando, Florida. Approximately 55 customers attended, including Orange County Commissioner Emily Bonilla and a legislative aide to State Senator Linda Stewart. Twenty-one customers spoke at the meeting. Approximately 12 customer comments received at the customer meeting concerned elevated Total Trihalimethanes (TTHM, a disinfection byproduct) levels.[5] The most recent DEP compliance test results, dated March 20, 2018, demonstrated that TTHM levels were in compliance with DEP standards.[6]

On March 6, 2018, the Office of Public Counsel (OPC) filed a letter in this docket expressing its concerns with the Utility's filing.[7] OPC's concerns are addressed in Issue 1.

As of April 2, 2018, 56 customers filed written comments in this docket. Fourty-six of the comments were concerning the quality of water and 46 comments opposed the rate increase. Two comments were concerning the Utility's customer service.[8]

This recommendation addresses Pluris' requested final rates. The Commission has jurisdiction pursuant to Sections 367.081 and 367.0822, Florida Statues (F.S.).

[2]Document No. 06333-2017.
[3]Document No. 06333-2017.
[4]Document No. 00091-2018.
[5]The Utility has recently completed a pilot study and received a new DEP permit to address TTHM levels.
[6]Document Nos. 10796-2017, 00091-2018, and 02727-2018.
[7]Document No. 02135-2018.
[8]Several customer comments had more than one concern listed.

Discussion of Issues

Issue 1: Should Pluris Wedgefield, Inc.'s requested increases be approved as filed?

Recommendation: No. Staff recommends incremental revenue requirement increases of $170,861 for water and $53,377 for wastewater as opposed to the Utility's requested incremental revenue requirement increases of $194,159 for water and $57,545 for wastewater. (L.Smith, P.Buys, D.Buys)

Staff Analysis: In its filing, Pluris requested recovery of costs associated with four projects: the installation of Advanced Metering Infrastructure (AMI) meters, the installation of water softening equipment, the construction of a maintenance building, and the replacement of a wastewater main. The Utility's initial filing provided a description of each project. Staff reviewed the Utility's filing and issued multiple data requests. Staff's analysis of each project is discussed in greater detail in the following section. All four of the projects have been completed.[9]

Incremental Rate Base

The Utility requested rate base increases of $1,042,165 for water and $355,783 for wastewater. The rate base components are Utility Plant in Service (UPIS), Accumulated Depreciation, and Working Capital Allowance.

Utility Plant in Service

AMI Meters

Pluris requested $594,648 to recover costs associated with installing approximately 1,641 AMI water meters. The old meters were installed between 1996 and 2015.[10] With the installation of the AMI meters, Pluris also implemented an internet portal that allows each customer the ability to observe their water usage. The AMI meter replacement program began in October 2015 and was completed in October 2016. Prior to the installation of the AMI meters, meters were read manually.[11]

In its petition, Pluris explained that meter reading related customer concerns have been an on-going issue. From January 1, 2013, to September 30, 2016, the Utility received 481 requests for meters to be re-read or tested. Many of the requests were generated due to customer usage concerns. Since the installation of the AMI meters, Pluris has received 68 requests for the meters to be re-read. Customers have indicated to the Utility that the new customer portal has assisted in identifying leaks and has alerted them to excessive usage.[12] Based on the reduction in requests for meters to be re-read, and the positive response about the customer portal, staff believes the proposed AMI project is reasonable.

The Utility obtained three bids for the major components of the AMI project ($367,969, $395,393, and $509,913). The major components include meters, transmitters, a base station,

[9]Document No. 06333-2017.
[10]Document No. 00907-2018.
[11]Document No. 06333-2017.
[12]Document Nos 06333-2017 and 00907-2018.

tower, and software.[13] Pluris chose the bid of $395,393 provided by HD Supply Waterworks. The Utility indicated that the lowest bid ($367,969) was not selected because it additionally required the acquisition of land and relied on cell and/or mobile phone signal technology. The Utility expressed concerns with the cell coverage in the community and potential issues with readings being missed.[14] The meters provided by HD Supply Waterworks use a single tower with one base station, which produces reliable and consistent data reads. In addition, the HD Supply Waterworks bid included the previously discussed customer portal and a discount on the installation of the new meters and removal of the old meters.[15]

Pluris provided 49 invoices associated with this project. The majority of the invoices were related to the HD Supply Waterworks bid. Additionally, the Utility provided invoices for the installation of the meters, capitalized labor for its employees that helped with the installation of the meters, installation of an AMI tower, and extra meters and parts for installation and repairs.[16] Two of the invoices were for geotechnical studies to determine a viable site for the tower. In response to a staff data request, the Utility explained that the studies were not duplicative as the first site studied was not suitable for reliable signaling to all meters; therefore, a second study was necessary. In addition, Pluris explained that state licensed professional engineers do not generally bid for work, due to ethical codes maintained as members in the American Society of Civil Engineers.[17] Based on review of the invoices provided by the Utility, staff recommends that $594,648 be allowed for cost recovery. The recommended amount includes costs associated with the HD Supply Waterworks bid as well as costs for the AMI tower and labor.

The Utility suggested retiring $224,489 for the meter project. When asked about the retirements, Pluris indicated $224,489 was the balance of account 334 Meters/Meter Installations at the end of 2015. The Utility further explained that the AMI project began in October 2015 and all invoices related to this project were coded to Account 105, Construction in Process. Pluris suggested that since the AMI meters were replacing all current in-service meters, the total account balance of $224,489 should be retired.[18] Staff's review of Pluris' 2015 Annual Report showed a balance of $217,093 in Account 334. However, since the new meters were placed in service in September of 2016, staff agrees with the Utility that the balance of Account 334 would have been sufficient at that time to retire $224,489 from that account. Therefore, staff recommends $224,489 be the associated retirement for this project.

Water Softener

The Utility requested recovery of $364,128 for the installation of water softener equipment. Pluris explained that the previous water softeners, which were installed by the previous owner of the system, were not meeting treatment levels and were experiencing ongoing mechanical and Supervisory Control and Data Acquisition (SCADA) related problems.[19] Pluris also explained that the raw water pumped from the Floridan Aquifer is rated as very hard (13-15 grains) based

[13]Document No. 02188-2018 and 0249-2018.
[14]Document No. 00907-2018.
[15]Document No. 10796-2017, 01203-2018, and 01974-2018.
[16]Document No. 00907-2018.
[17]Document No. 02498-2018.
[18]Document No. 00907-2018.
[19]Document No. 01839-2018.

on standards established by the American Society of Agricultural Engineers (ASAE).[20] Hard water can cause scaling and noticeable deposits in containers, which was an issue that Pluris' customers have complained about.[21] The Utility specified that the water currently delivered to customers is now between 3 to 4 grains of hardness.[22] Additionally, Pluris indicated that it has received recent calls from customers stating that the water was soft and there was no longer calcium on glassware and utensils.[23] Considering the operational issues of the previous water softener system, and the improvements discussed above, staff believes it was prudent for the Utility to install the new water softening equipment.

The Utility obtained three bids on water softener products: $112,805, $142,900, and $315,000. Pluris explained that the two companies with the lowest bids could not provide products that addressed the flow requirements, level of hardness reduction, nor the ability to integrate piping and SCADA required for the plant. The highest bidder demonstrated a more thorough understanding of the scope and requirements of the project.[24]

Pluris provided eight invoices that included the water softener equipment and a shade structure to protect the equipment.[25] The Utility explained there was no previous structure in place for the old equipment.[26] Pluris provided bids for the shade structure.[27] The actual invoices for the shade structure were approximately $2,600 cheaper than the bids. Staff reviewed the invoices and believes that all costs were prudently incurred. Therefore, staff recommends $364,128 be allowed for recovery for the water softener project.

The Utility suggests the amount to be retired for this project should be $248,850.[28] This amount is 75 percent of $331,800, which is only the amount for the replacement of the water softener equipment. Because there was no previous structure for the old equipment, there is no retirement amount associated with the shade structure.[29] Staff recommends that the associated retirement for the water softener equipment is $248,850.

Maintenance Building

Pluris requested recovery of $105,090 for a new maintenance building. The Utility explained that the water treatment plant did not have a dedicated office for its staff to conduct daily work. Pluris further explained that an existing electrical building was being used and was inadequate.[30] According to the Utility, the daily activities required to efficiently operate the water treatment facility include operation of SCADA, clerical duties, and laboratory work. The equipment required to complete this daily work includes computers, a printer, desks, chairs, tables, metering

[20] Document Nos. 06333-2017 and 01839-2018. Less than 1.0 grains per gallon is considered soft and greater than 10.5 grains per gallon is considered very hard.
[21] Document No. 06333-2017 and 01839-2018.
[22] Document No. 06333-2017.
[23] Document No. 00907-2018.
[24] Document No. 00907-2018.
[25] Document No. 10796-2017.
[26] Document No. 00907-2018.
[27] Document No. 02498-2018.
[28] Document No. 06333-2017.
[29] Document No. 00907-2018.
[30] Document No. 06333-2017.

equipment for operation and process control, and lab equipment. The computers are used to monitor SCADA performance, which is additional equipment not previously used.[31] Pluris stated that the average number of employees using the building at one time would be two to three. In addition, there could be times when more employees would be using the building. The Utility further explained that in addition to the equipment listed above, this building would have bathroom facilities, as the electrical building did not.[32] Considering the old space in the electrical building used for the employees to conduct daily work and the new equipment needed, staff believes a dedicated office for Pluris' staff is appropriate.

The bids that Pluris acquired for only the maintenance building were $34,540, $25,000, and $22,209. The Utility selected the lowest bid.[33] Pluris provided ten invoices for this project. In addition to invoices associated with the building, Pluris provided invoices for permitting, electrical work, a driveway and parking for the building.[34] The Utility also provided a bid for those services.[35] One invoice for $3,282 included a line item labeled "Maxim Break and Site Permitting for Office." The Utility explained the "Maxim Break" was for an emergency repair. The company billing Pluris grouped these two separate projects together. That company estimated the "Maxim Break" was $2,300 and the Site Permitting was $982.[36] Staff believes that the "Maxim Break" should not be included in the maintenance building project. Therefore, staff recommends that $102,790 ($105,090 - $2,300) should be recovered for this project. Since this is a new structure there are no retirements associated with this project.

Wastewater Main Replacement

The Utility requested $359,023 to replace a wastewater main. Pluris explained the sewer main collapsed during an attempt to clear debris from the pipeline. Approximately 300 feet of sewer line was excavated and replaced.[37] The Utility further explained that the pipeline material was asbestos concrete and was nearly 40 years old. Pluris indicated that the pipeline exceeded its design life and deteriorated causing the collapse.[38] Included in this project were repairing, resurfacing, line painting, and landscaping of the affected roadway.[39]

Pluris did not request bids for this project as it was an emergency repair.[40] The Utility provided one invoice from Tri-Sure Corporation for this project. Staff reviewed the invoice and all the line items appear to be related to this project.[41] Therefore, staff recommends $359,023 be recovered for this project. The suggested amount for the retirement of this project is $269,267.[42] This amount is 75 percent of the project amount of $359,023. Staff believes this is appropriate and recommends the associated retirement for the wastewater main replacement should be $269,267.

[31]Document No. 00907-2018.
[32]Document No. 01667-2018.
[33]Document No. 00907-2018.
[34]Document No. 10796-2017.
[35]Document No. 02498-2018.
[36]Document No. 00907-2018.
[37]Document No. 06333-2017.
[38]Document No. 10796-2017.
[39]Document No. 06333-2017.
[40]Document No. 00907-2018.
[41]Document No. 10796-2017.
[42]Document No. 06333-2017.

Accumulated Depreciation

In its filing, the Utility calculated accumulated depreciation using a half-year convention. Because rates will be going into effect in 2018, staff believes it is more appropriate to include a full year's depreciation. This is consistent with Commission practice for the treatment of pro forma projects. As a result, accumulated depreciation should be increased for the AMI meters by $29,732, which represents one year's depreciation on the new meters. As discussed earlier, staff recommends that accumulated depreciation for the AMI meters be reduced by $224,489 to account for the retired meters. Therefore, staff recommends a net reduction to accumulated depreciation for Meters & Meter Installations of $194,757 ($224,489 - $29,732).

Also, as discussed earlier, staff recommends reducing accumulated depreciation by $248,850 for the retirement of the water softener. Accumulated depreciation should be increased by $15,082, which represents one year's depreciation on the new water softener. Therefore, staff recommends a net reduction to accumulated depreciation for the Water Treatment Equipment of $232,880 ($248,850 - $15,082).

Further, staff recommends increasing accumulated depreciation by $2,705 to reflect one year's depreciation on the new maintenance building. Therefore, staff recommends a total decrease to water accumulated depreciation of $424,932 ($194,757 + $232,880 - $2,705).

As stated earlier, staff recommends decreasing accumulated depreciation by $269,267 to reflect the appropriate retirement associated with the wastewater main replacement. Accumulated depreciation should also be increased by $7,978, which represents one year's depreciation on the new wastewater main. Staff therefore recommends a net reduction to wastewater accumulated depreciation of $261,289 ($269,267 - $7,978). The Utility's requested amounts and staff's recommended amounts are shown below in Table 1-1 for water and Table 1-2 for wastewater.

Table 1-1
Summary of Water Plant Projects

	Utility's Request	Staff Recommended	Difference
AMI Meters	$594,648	$594,648	$0
Retirement	($224,489)	($224,489)	$0
Accumulated Depreciation	($209,623)	($194,757)	$14,866
Water Softener	$364,128	$364,128	$0
Retirement	($248,850)	($248,850)	$0
Accumulated Depreciation	($240,865)	($232,880)	$7,985
Maintenance Building	$105,090	$102,790	($2,300)
Retirement	$0	$0	0
Accumulated Depreciation	($1,555)	$2,705	($1,150)

Source: Utility's Filing

Table 1-2
Summary of Wastewater Plant Projects

	Utility's Request	Staff Recommended	Difference
Wastewater Main Break	$359,023	$359,023	$0
Retirement	($269,267)	($269,267)	$0
Accumulated Depreciation	($265,278)	($261,289)	$3,989

Source: Utility's Filing

Working Capital Allowance

Working capital is defined as the short-term investor-supplied funds that are necessary to meet operating expenses. Consistent with Rule 25-30.433(2), F.A.C., staff used the one-eighth of the operation and maintenance expense formula approach for calculating the working capital allowance. Applying this formula, staff recommends an increase to the working capital allowance of $576 for water and $372 for wastewater.

Rate Base Summary

Based on the foregoing, staff recommends a rate base increase of $1,013,734 for water and $351,416 for wastewater. Staff's rate base calculations are shown on Schedule Nos. 1 and 2.

Rate of Return

The Utility calculated the weighted average cost of capital correctly in accordance with Rule 25-30.455(4)(e), F.A.C., which states:

> (e) A calculation of the weighted average cost of capital shall be provided for the most recent 12-month period, using the mid-point of the range of the last authorized rate of return on equity, the current embedded cost of fixed-rate capital, the actual cost of short-term debt, the actual cost of variable-cost debt, and the actual cost of other sources of capital which were used in the last individual rate proceeding of the utility. If the utility does not have an authorized rate of return on equity, the utility shall use the current leverage formula pursuant to Section 367.081(4)(f), F.S.

In its filing, Pluris provided a weighted average cost of capital (rate of return) of 9.21 percent, based on a capital structure consisting of 67.79 percent equity and 31.75 percent debt using the most recent 12-month period ended December 31, 2016. Pluris used a return on equity (ROE) of 10.88 percent, which is the mid-point of the range of the last authorized rate of return on equity established in its last rate case by Order No. PSC-13-0187-PAA-WS, issued May 2, 2013, (2012 Rate Case).[43] Staff made one adjustment to the cost of capital as filed by the Utility. Consistent with Rule 25-30.311(4)(a), F.A.C., staff reduced the cost rate for customer deposits from the Utility's proposed 6.00 percent to 2.00 percent. Staff's adjustment reduced the Utility's requested rate of return from 9.21 percent to 9.20 percent.

In a letter dated March 6, 2018, OPC asserted that the Utility's requested ROE and resulting rate of return is overstated and unreasonable. OPC requested that the Commission, on its own motion, make a finding regarding the appropriate ROE and the appropriate overall rate of return in this Limited Proceeding. OPC pointed out that Pluris' overall rate of return was last established in the 2012 Rate Case, and in that docket, the Commission approved an equity ratio of 42.97 percent and used the leverage formula in effect at that time. The same leverage formula is still in effect currently. OPC stated that because of an increase in the Utility's equity ratio (42.97 percent to 67.19 percent), the ROE should be recalculated using the current equity ratio, resulting in a ROE of 9.49 percent.

Staff believes recalculating the ROE does not comply with the calculation of the weighted average cost of capital as prescribed in Rule 25-30.455(4)(e), F.A.C. Additionally, the recalculated ROE would apply only to the limited proceeding, resulting in Pluris operating under two different rates of return. Further, a reduction of the Utility's ROE from 10.88 to 9.49 percent would result in Pluris earning below its authorized range of ROE on the new plant investment. The authorized range of ROE established in the 2012 Rate Case was 9.88 percent to 11.88 percent.

OPC also pointed out that Rule 25-30.445(5)(e), F.A.C., requires the Utility to provide a description of any known items that will create a cost savings or revenue impacts from the implementation of the requested cost recovery items. OPC argues the increase in equity ratio

[43]Order No. PSC-13-0187-PAA-WS, issued May 2, 2013, in Docket No. 20120152-WS, *In re: Application for increase in water and wastewater rates in Orange County by Pluris Wedgefield, Inc.*

results in a known cost savings for which Pluris was required to include in its original petition or revised schedules, but did not do so.

Staff reviewed Paragraph (5) of Rule 25-30.445, F.A.C., and notes that Paragraph (5) applies only to class C water or wastewater utilities. Since Pluris is a class B water and wastewater utility, Paragraph (5) does not apply to Pluris.

OPC opined that there is past precedent where the Commission reduced the rate of return on equity in a limited proceeding to a rate different than the rate approved in the last rate proceeding for a given utility. OPC cited to Order No. PSC-99-1917-PAA-WS, issued September 28, 1999, (Aloha Order), wherein the Commission found that based on the leverage formula in effect at the time of the limited proceeding, Aloha Utilities, Inc.'s last authorized ROE was excessive.[44]

Staff believes that deviating from the rule requirement is not appropriate. Other than the one exception noted by OPC, ROEs have not been addressed in water and wastewater limited proceedings. The limited proceeding rule specifically addresses increases in rate base, operating expenses, and changes in rate structure. The rule does not reference requested changes to ROE. ROE is appropriately addressed in a full rate case whereby all aspects of the capital structure are analyzed. In general, staff would not recommend reducing or increasing ROE in a limited proceeding. In addition, staff notes that the fact pattern in the Aloha Order is not analogous to the fact pattern in the instant case.

Staff believes there are three reasons why the instant case and the Aloha case are not analogous. First, in the Aloha case, the ROE that was changed by the Commission was set in 1977, which was twenty-two years before the Aloha Order was issued. During those 22 years, the leverage formula had changed many times. In the instant case, the Commission established Pluris' ROE of 10.88 percent six years ago in 2012 and the leverage formula that was used at that time is still in effect today. Second, Aloha Utilities, Inc. consisted of two systems in different service territories and with separate rates: Aloha Gardens and Seven Springs. In 1992, the Commission established an ROE of 12.69 percent for the Aloha Gardens wastewater system.[45] At the time of the 1999 Aloha limited proceeding, the ROE for the Aloha Gardens water system and both Seven Springs water and wastewater systems was 14.00 percent. The Commission determined that 14.00 percent was excessive for the three Aloha systems and reduced the ROE to 10.12 percent using the leverage formula in effect at the time. Third, Rule 25-30.445, F.A.C., became effective on March 1, 2004, and was not available when the Commission made its decision in the Aloha Order in 1999. Therefore, in the Aloha limited proceeding decision, the Commission did not deviate from an existing Commission Rule when it recalculated and changed the authorized ROE.

[44]Order No. PSC-99-1917-PAA-WS, issued September 28, 1999, in Docket No. 19970536-WS, *In re: Application for limited proceeding in water and wastewater rates in Pasco County by Aloha Utilities, Inc.* and Docket No. 19980245-WS, *In re: Application for limited proceeding in water and wastewater rates in Pasco County by Aloha Utilities, Inc.*

[45]Order No. PSC-92-0578-FOF-SU, issued June 29, 1992, in Docket No. 19910540-SU, *In re: Application for Sewer service rate adjustment in Aloha Gardens service area by Aloha Utilities, Inc., in Pasco County.*

Based on the reasons explained above, staff does not recommend the Commission set a new ROE for the Utility in this limited proceeding. Therefore, staff recommends an overall rate of return of 9.20 percent. This results in a return on rate base of $93,245 ($1,013,737 x 9.20 percent) for water and $32,324 ($351,416 x 9.20 percent) for wastewater. The cost of capital calculation is shown below in Table 1-3.

Table 1-3
Capital Structure

Description	Total Capital 12/31/2016	Ratio	Cost	Weighted Cost
Long-Term Debt	$3,650,745	31.75%	5.73%	1.82%
Common Equity	7,795,507	67.79%	10.88%	7.38%
Customer Deposits	23,826	0.21%	2.00%	0.00%
Deferred Taxes	29,076	0.25%	0.00%	0.00%
Total Capitalization	$11,499,154	100.00%		9.20%

Source: Utility's Filing

Operating Expenses

In its petition, Pluris requested an increase to operating expenses of $98,185 for water and $24,780 for wastewater. The components for the operating expenses were Depreciation Expense, Regulatory Commission Expense, Rent Expense, Maintenance Expense, Meter Reading Expense, Taxes Other Than Income, Income Taxes, and Regulatory Assessment Fees (RAF).

Depreciation Expense

In its filing, the Utility requested an increase in Depreciation Expense of $26,273 for water and $1,994 for wastewater. Staff calculated depreciation expense using the prescribed rates set forth in Rule 25-30.140, F.A.C. Based on staff's recommended increases in rate base, staff recommends a net increase in depreciation expense of $25,871 for water and $1,994 for wastewater. This equates to a reduction of $402 for water.

Regulatory Commission Expense

In its filing, the Utility requested $47,960 in Rate Case Expense. This included $39,960 for Legal Fees and $1,500 for Costs Associated with Legal Services (Legal Costs). On February 2, 2017, staff received invoices from Friedman & Friedman for $12,315 for billed and unbilled legal services with an additional $4,625 as an estimate to complete the limited proceeding. Those invoices also included $2,907 for legal costs with an additional $20 to complete the limited proceeding. This amount included the $2,000 filing fee.

Pursuant to Section 367.081(7), F.S., the Commission shall determine the reasonableness of rate case expenses and shall disallow all rate case expenses determined to be unreasonable. Staff has examined the requested actual expenses, supporting documentation, and estimated expenses for the current rate case. Staff compared these costs with those approved in Docket No. 20090349-

WS.[46] The Utility in that docket was similarly-sized as was the requested revenue increase. Staff believes the documented legal fees and costs are reasonable and prudent, as are the estimated costs to complete. Therefore, staff recommends $2,000 for the filing fee, $16,940 ($12,315 + $4,625) for legal fees, and $907 ($2,887 - $2,000 + $20) for legal costs.

The Utility requested $1,500 for postage and $1,000 for customer notices. By Rule 25-30.446, F.A.C., Pluris is required to mail a notice of the customer meeting and notices of final rates in this case to its customers. Staff has estimated these costs to be $1,632 for postage and $1,154 for envelopes and printing the customer meeting and final rate notices. Therefore, staff recommends increasing the postage expense by $132 ($1,632 - $1,500) and the customer notices by $154 ($1,154 - $1,000).

The Utility also requested expenses related to Maurice Gallarda, the Utility's President, and Principal Engineer, to attend the Agenda Conference. These estimates were $1,000 for airfare, $400 for two nights in a hotel, $300 for a rental car, and $300 for meals.

In an email dated March 15, 2018, staff contacted Mr. Friedman requesting receipts for the above expenses. Mr. Friedman provided a receipt for $927 for the airfare and $164 for the hotel. Mr. Friedman also stated in the email that he would provide transportation for Mr. Gallarda, and he also changed the Meal Allowance request to $60 total.[47] Staff compared the requested Meal Allowance to the amount approved in Docket No. 20070695-WS, [48] which was $80. Staff believes these amounts are reasonable. Therefore, staff reduced the airfare by $73 ($1,000 - $927), reduced the rental care expense by $300 ($0 - $300), decreased the hotel expense by $236 ($400 - $164), and decreased the meal allowance by $240 ($300 - $60) to reflect the documented and requested costs of these expenses.

Based on the above, staff recommends that the total rate case expense is $23,784, which amortized over four years results in a regulatory commission expense of $5,946 ($23,784 ÷ 4), or $2,973 for water and wastewater. These costs and staff's adjustments are summarized below in Table 1-4.

[46]Order No. PSC-10-0682-PAA-WS, issued November 15, 2010, in Docket No. 20090349-WS, *In re: Application for limited proceeding rate increase in Polk County by Cypress Lakes Utilities, Inc.*
[47] Document Nos. 02404-2018 and 02410-2018.
[48]Order No. PSC-08-0812-PAA-WS, issued December 16, 2008, in Docket No. 20070695-WS, *In re: Application for increase in water and wastewater rates in Martin County by Miles Grant Water and Sewer Company.*

Table 1-4
Regulatory Commission Expense

	Per Utility	Adjs	Staff Recommended
Filing Fee	$2,000	$0	$2,000
Legal Fees	39,960	(23,020)	16,940
Legal Fees	1,500	(593)	907
Postage	1,500	132	1,632
Customer Notices	1,000	154	1,154
Airfare	1,000	(73)	927
Hotel	400	(236)	164
Rental Car	300	(300)	0
Meals	300	(240)	60
	$47,960	($24,176)	$23,784

Source: Utility's Filing

Rent Expense

In its filing, the Utility requested $9,000 for rental expense related to a tower that was to be used for the AMI meters. In response to Staff's Third Data Request, the Utility agreed this expense is no longer needed. Therefore, staff has removed $9,000 for the tower rental expense.

Maintenance Expense

In its filing, the Utility requested an increase of $17,739 for maintenance expense. This amount consists of the AMI software setup and yearly AMI software maintenance costs. Consistent with Commission practice, because the AMI software setup costs are a non-recurring expense, this amount was amortized over a five year period. This results in an amount of $2,612 ($13,063 ÷ 5). Staff reviewed the invoices related to the AMI software maintenance costs. Those invoices reflect a yearly maintenance expense of $10,124. Staff has reduced this expense by $5,003 ($15,127 - $10,124) to reflect the actual cost. Therefore, staff is recommending a total maintenance expense of $12,736 ($2,612 + $10,124).

Meter Reading Expense

In its filing, the Utility reflected a reduction in Salary Expense of $11,100. This is a result of the elimination of the meter reader position previously used by the Utility. The calculation of this amount is shown below in Table 1-5.

Table 1-5
Reduction to Meter Reading Expense

Annual Salary	$27,726
Estimate of Benefits	5,545
Salary & Benefits	$33,271
Truck & Fuel	3,852
Total Meter Reader Costs	$37,123
Pluris Wedgefield Allocation Factor	29.90%
Meter Reader Allocation	$11,100

Source: Utility's Filing

Taxes Other Than Income

Staff calculated the increase in property taxes based on the recommended increase in UPIS. Because the 2018 millage rates for Orange County are not known at this time, staff used the rate from the Utility's 2017 tax assessment. Consistent with Commission practice, staff used the four percent discount that is available to the Utility for early payment of its property taxes. Staff recommends an increase in property taxes of $16,146 for water and $5,594 for wastewater.

Based on staff's recommendations above, staff is recommending an increase to expenses before income taxes and RAFs of $46,625 for water and $10,561 for wastewater. These calculations are shown below in Table 1-6 and Table 1-7.

Table 1-6
Expenses Before Income Taxes and RAFs

	Per Utility	Adjs	Staff Recommended
Depreciation Expense	$26,273	($402)	$25,871
Rate Case Expense	5,995	(3,022)	2,973
Rent Expense	9,000	(9,000)	0
Maintenance Expense	17,739	(5,003)	12,736
Meter Reading Expense	(11,100)	0	(11,100)
TOTI	17,626	(1,480)	16,146
Total Increase in Operating Exp	$65,533	($18,908)	$46,625

Source: Utility's Filing

Table 1-7
Expenses Before Income Taxes and RAFs

	Per Utility	Adjs	Staff Recommended
Depreciation Expense	$1,994	($0)	$1,994
Rate Case Expense	5,995	(3,022)	2,973
TOTI	6,020	(426)	5,594
Total Increase in Operating Exp	$14,009	($3,448)	$10,561

Source: Utility's Filing

Income Taxes

Staff calculated state and federal income taxes based on the current rates of 5.5 percent for state and 21 percent for federal. Staff notes that the federal taxes in this case are adjusted to reflect the new rate set forth in the 2017 Tax Cut and Jobs Act and only affects the incremental increases in this case. Any potential refund related to the change in the federal tax rate currently embedded in the Utility's rates is outside of this proceeding and will be addressed in the generic Docket No. 20180013-PU.[49] Based on staff's recommended return on rate base, staff recommends an increase in state taxes of $5,128 ($93,245 x .055) for water and $1,778 ($32,324 x .055) for wastewater. Staff further recommends increases to federal income taxes of $18,505 (($93,245 - $5,129) x .21) for water and $6,415 (($32,324 - $1,778) x .21) for wastewater.

Regulatory Assessment Fees (RAF)

Based on the above, staff is recommending a revenue increase before RAFs of $163,503 for water and $51,078 for wastewater. Therefore, staff recommends RAFs should be increased by $7,358 ($163,503 x 4.5 percent) for water and $2,299 ($51,078 x 4.5 percent) for wastewater.

Operating Expenses Summary

Based on the above, staff is recommending an incremental increase to Operating Expenses of $77,616 for water and $21,053 for wastewater. Staff's calculations are shown on Schedule Nos. 1 and 2.

Conclusion

Based on the above, staff recommends an incremental revenue requirement increase of $170,861 for water and $53,377 for wastewater. This represents increases of 12.16 percent and 5.53 percent for water and wastewater, respectively. The Utility requested an incremental revenue requirement increase of $194,159 for water and $57,545 for wastewater. Staff's revenue requirement calculations are shown on Schedule Nos. 1 and 2.

[49]Docket No. 20180013-PU, *In re: Petition to establish a generic docket to investigate and adjust rates for 2018 tax savings, by Office of Public Counsel.*

Issue 2: What are the appropriate water and wastewater rates for Pluris Wedgefield, Inc.?

Recommendation: The recommended monthly water rates are shown on Schedule No. 3 and the recommended monthly wastewater rates are shown on Schedule No. 4. The recommended rates should be designed to produce additional revenues of $170,861 (12.16 percent increase) for water and $53,377 (5.53 percent increase) for wastewater. The percent increases should be applied as an across-the-board increase to the existing rates. The Utility should file revised tariff sheets and a proposed customer notice to reflect the Commission-approved rates. The approved rates should be effective for service rendered on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. In addition, the approved rates should not be implemented until staff has approved the proposed customer notice and the notice has been received by the customers. The Utility should provide proof of the date notice was given within 10 days of the date of the notice. (Friedrich)

Staff Analysis: Staff recommends that service rates for Pluris Wedgefield be designed to allow the Utility the opportunity to generate annual service revenues of $1,575,497 for water and $1,018,335 for wastewater. The annualized service revenues before the rate increase are $1,404,636 for water and $964,958 for wastewater. This results in a 12.16 percent increase for water and a 5.53 percent increase for wastewater service revenues. The corresponding percentage increases should be applied as an across-the-board increase to the existing water and wastewater rates.

Based on the above, the recommended monthly water rates are shown on Schedule No. 3 and the recommended monthly wastewater rates are shown on Schedule No. 4. The recommended rates should be designed to produce additional revenues of $170,861 (12.16 percent increase) for water and $53,377 (5.53 percent increase) for wastewater. The percent increases should be applied as an across-the-board increase to the existing rates. The Utility should file revised tariff sheets and a proposed customer notice to reflect the Commission-approved rates. The approved rates should be effective for service rendered on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. In addition, the approved rates should not be implemented until staff has approved the proposed customer notice and the notice has been received by the customers. The Utility should provide proof of the date notice was given within 10 days of the date of the notice.

Issue 3: Should the meter installation charge requested by Pluris Wedgefield, Inc. be approved?

Recommendation: Yes. The meter installation charge of $268 for a 5/8" x 3/4" meter and actual cost for all other meter sizes should be approved. The Utility should file revised tariff sheets and a proposed customer notice. Pluris should provide notice to property owners who have requested service within the 12 calendar months prior to the month the application was filed to the present. The approved charges should be effective for connections made on or after the stamped approval date on the tariff sheets. The Utility should provide proof of the date notice was given within 10 days of the date of the notice. (Friedrich)

Staff Analysis: The Utility currently has a meter installation charge of $110 for a 5/8" x 3/4" meter and $170 for a 1" meter which were approved in an application for original certificates in 1983.[50] A meter installation charge is designed to recover the cost of the meter and the installation. Pluris is requesting an increase in its meter installation charge to reflect the current costs of installing an AMI meter. The requested meter installation charge includes, $115 for the meter, $130 for the transmitter, and $23 for the meter box. To additionally justify these cost components, the Utility provided a quote for the meter, transmitter, and the meter box. The Utility's requested meter installation charges are consistent with meter installation charges previously approved by the Commission for other utilities.

Staff believes the Utility's request is reasonable and should be approved. Based on the above, the meter installation charge of $268 for a 5/8" x 3/4" meter and actual cost for all other meter sizes should be approved. The Utility should file revised tariff sheets and a proposed customer notice. Pluris should provide notice to provide property owners who have requested service within the 12 calendar months prior to the month the application was filed to the present. The approved charges should be effective for connections made on or after the stamped approval date on the tariff sheets. The Utility should provide proof of the date notice was given within 10 days of the date of the notice.

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[50] Order No. 12315, issued August 4, 1983, in Docket No. 820323-WS, *In re: Application of Econ Utilities Corporation for original water and sewer certificates in Orange Florida.*

Issue 4: What is the appropriate amount by which rates should be reduced in four years after the published effective date to reflect the removal of the amortized rate case expense as required by Section 367.081(8), F.S?

Recommendation: The water and wastewater rates should be reduced, as shown on Schedule Nos. 3 and 4, to remove rate case expense grossed-up for RAFs and amortized over a 4-year period. The decrease in rates should become effective immediately following the expiration of the four-year rate case expense recovery period, pursuant to Section 367.081(8), F.S. Pluris should be required to file revised tariffs and a proposed customer notice setting forth the lower rates and the reason for the reduction no later than one month prior to the actual date of the required rate reduction. If the Utility files this reduction in conjunction with a price index or pass-through rate adjustment, separate data should be filed for the price index and/or pass-through increase or decrease and the reduction in the rates due to the amortized rate case expense. (L. Smith, M. Friedrich)

Staff Analysis: Section 367.081(8), F.S., requires that the rates be reduced immediately following the expiration of the 4-year period by the amount of the rate case expense previously included in rates. The reduction will reflect the removal of revenue associated with the amortization of rate case expense, the associated return in working capital, and the gross-up for RAFs. This results in a reduction of $3,152 for water and wastewater.

The water and wastewater rates should be reduced, as shown on Schedule Nos. 3 and 4, to remove rate case expense grossed-up for RAFs and amortized over a 4-year period. The decrease in rates should become effective immediately following the expiration of the 4-year rate case expense recovery period, pursuant to Section 367.081(8), F.S. Pluris should be required to file revised tariffs and a proposed customer notice setting forth the lower rates and the reason for the reduction no later than one month prior to the actual date of the required rate reduction. If the Utility files this reduction in conjunction with a price index or pass-through rate adjustment, separate data should be filed for the price index and/or pass-through increase or decrease and the reduction in the rates due to the amortized rate case expense.

Issue 5: 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. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff. Once these actions are complete, this docket should be closed administratively. (D. Janjic)

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. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff. Once these actions are complete, this docket should be closed administratively.

Water Revenue Requirement			
	Per Utility	Adjustment	Staff Recommended
UPIS	$1,063,865	($2,300)	$1,061,565
Retirements	(473,339)	0	(473,339)
Less: Accumulated Depreciation	(448,935)	24,003	(424,932)
Working Capital	2,704	(2,128)	576
Total Increase in Rate Base	$1,042,165	($28,431)	$1,013,734
Weighted Cost of Capital	9.21%		9.20%
Return on Rate Base	$95,860		$93,245
Depreciation Expense	$26,273	($402)	$25,871
Rate Case Expense	5,995	(3,022)	2,973
Rent Expense	9,000	(9,000)	0
Maintenance Expense	17,739	(5,003)	12,736
Meter Reading Expense	(11,100)	0	(11,100)
TOTI	17,626	(1,480)	16,146
State Income Tax (5.5%)	5,277	(149)	5,128
Federal Income Tax (21%)	19,041	(536)	18,505
Regulatory Assessment Fees	8,356	(998)	7,358
Total Operating Expenses	$98,207	($20,592)	$77,616
Total Revenue Increase Requested/Recommended	$194,159		$170,861
Annualized Revenue	$1,404,636		$1,404,636
Percentage Increase	13.81%		12.16%

Wastewater Revenue Requirement			
	Per Utility	Adjustment	Staff Recommended
UPIS	$359,023	$0	$359,023
Retirements	(269,267)	0	(269,267)
Less: Accumulated Depreciation	(265,278)	3,989	(261,289)
Working Capital	749	(377)	372
Total Increase in Rate Base	$355,783	($4,367)	$351,416
Weighted Cost of Capital	9.21%		9.20%
Return on Rate Base	$32,755		$32,324
Depreciation Expense	$1,994	$0	$1,994
Rate Case Expense	5,995	(3,022)	2,973
TOTI	6,020	(426)	5,594
State Income Tax (5.5%)	1,802	(24)	1,778
Federal Income Tax (21%)	6,500	(85)	6,415
Regulatory Assessment Fees	2,478	(179)	2,299
Total Operating Expense	$24,789	($3,736)	$21,053
Total Revenue Increase Requested/Recommended	$57,545		$53,377
Annualized Revenue	$964,958		$964,958
Percentage Increase	5.96%		5.53%

PLURIS WEDGEFIELD, INC.
MONTHLY WATER RATES

SCHEDULE NO. 3
DOCKET NO. 20170166-WS

	UTILITY CURRENT RATES	STAFF RECOMMENDED RATES	4 YEAR RATE REDUCTION
Residential, General, and Irrigation Service			
Base Facility Charge by Meter Size			
5/8" X 3/4"	$24.71	$27.71	$0.06
3/4"	$37.08	$41.57	$0.08
1"	$61.79	$69.28	$0.14
1-1/2"	$123.58	$138.55	$0.28
2"	$197.74	$221.68	$0.44
3"	$395.48	$443.36	$0.89
4"	$617.92	$692.75	$1.39
6"	$1,235.86	$1,385.50	$2.77
Charge per 1,000 gallons- Residential and Residential Irrigation Service			
0-5,000 gallons	$7.79	$8.74	$0.02
5,001-10,000 gallons	$9.68	$10.86	$0.02
Over 10,000 gallons	$14.52	$16.29	$0.03
Charge per 1,000 gallons- General and General Irrigation Service	$8.79	$9.86	$0.02
Typical Residential 5/8" x 3/4" Meter Bill Comparison			
3,000 Gallons	$48.08	$53.93	
5,000 Gallons	$63.66	$71.41	
8,000 Gallons	$92.70	$103.99	

PLURIS WEDGEFIELD, INC. MONTHLY WASTEWATER RATES			SCHEDULE NO. 4 DOCKET NO. 20170166-WS
	UTILITY CURRENT RATES	STAFF RECOMMENDED RATES	4 YEAR RATE REDUCTION
Residential Service			
Base Facility Charge- All Meter Sizes	$29.01	$30.61	$0.09
Charge per 1,000 gallons- Residential	$4.24	$4.47	$0.01
8,000 gallon cap			
General Service			
Base Facility Charge by Meter Size			
5/8" X 3/4"	$29.01	$30.61	$0.09
3/4"	$43.52	$45.92	$0.14
1"	$72.55	$76.53	$0.24
1-1/2"	$145.07	$153.05	$0.47
2"	$232.11	$244.88	$0.76
3"	$464.22	$489.76	$1.52
4"	$725.35	$765.25	$2.37
6"	$1,450.71	$1,530.50	$4.74
Charge per 1,000 gallons - General Service	$5.08	$5.36	$0.02
Typical Residential 5/8" x 3/4" Meter Bill Comparison			
3,000 Gallons	$41.73	$44.02	
5,000 Gallons	$50.21	$52.96	
8,000 Gallons	$62.93	$66.37	

Item 5

FILED 4/26/2018
DOCUMENT NO. 03225-2018
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

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

RECEIVED-FPSC
2018 APR 26 PM 9:20
COMMISSION
CLERK

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

DATE: April 26, 2018

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Guffey) SKG CB EJD PD
Office of the General Counsel (Crawford) CM for JC

RE: Docket No. 20180089-EI – Petition for approval of modifications to rate schedule LS-1, lighting service and for approval of revisions to lighting service contract, by Duke Energy Florida, LLC.

AGENDA: 05/08/18 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 06/04/18 (60-Day Suspension Date)

SPECIAL INSTRUCTIONS: None

Case Background

On April 4, 2018, Duke Energy Florida, LLC (DEF or utility) filed a petition for approval of modifications to its Lighting Service (LS-1) rate schedule and lighting service contract. The LS-1 tariff is applicable to any customer for the sole purpose of lighting roadways or other outdoor areas. The proposed tariffs in legislative format are shown in Attachment A to this recommendation.

The proposed revisions are designed to update and clarify certain provisions of the LS-1 tariff; none of the rates and charges LS-1 customers currently pay are being modified. The Commission has jurisdiction over this matter pursuant to Section 366.06, Florida Statutes.

Discussion of Issues

Issue 1: Should the Commission approve DEF's proposed changes to its LS-1 rate schedule and lighting service contract as shown in Attachment A?

Recommendation: Yes. The Commission should approve the proposed changes to DEF's LS-1 rate schedule and lighting service contract as shown in Attachment A. The revised tariffs should become effective on May 8, 2018. (Guffey)

Staff Analysis: DEF's proposed revisions to its LS-1 rate schedule (Tariff Sheet Nos. 6.283 and 6.284) and lighting service contract (Tariff Sheet Nos. 7.110, 7.111, 7.112, and 7.113) are attached. The revisions are discussed below.

Each fixture shown in the LS-1 tariff indicates the lamp wattage (i.e., the amount of energy a lamp uses). DEF proposes to add language to indicate that actual wattages may vary up to five watts from the wattage shown in the tariff. DEF explained that the newer LED fixtures are more energy efficient in that they have equivalent lumen output with lower wattages compared to previous generation LED fixtures. Adding this language allows DEF to purchase more efficient products without having to update the LS-1 tariff to revise the wattages.

A lighting customer is required to pay a contribution in aid of construction (CIAC) when DEF extends its distribution facilities to provide lighting service. Currently, the CIAC is collected as a one-time payment. As an alternative to the one-time CIAC payment, DEF is proposing to allow customers to pay the CIAC amount as a monthly fee added to the bill. The monthly fee would apply as long as the customer takes service under the LS-1 tariff and is calculated as a percentage of the CIAC amount. The new language does not prohibit a customer from paying the total CIAC amount in a single payment.

In addition, DEF proposes tariff modifications to state that customers must notify the utility before installing customer-owned receptacles such as holiday lights. The added language helps the utility track the receptacles to manage electric load and to appropriately bill for energy consumption.

The proposed tariff is also revised to remove the language which states that the utility may consider installing and maintaining customer-owned systems. DEF states that, as a business practice, it will no longer consider such requests for customer-owned systems. Additionally, new language is included to clarify the pole replacement process making it consistent with the process currently used for replacing obsolete lighting fixtures.

The proposed revisions to the lighting service contract align it with proposed revisions to the LS-1 tariffs discussed above, remove language that is no longer necessary, and revise the utility's name to reflect Duke Energy Florida, LLC.

Staff has reviewed DEF's petition and believes the proposed changes to the LS-1 rate schedule and lighting service contract are reasonable and appropriate. Staff recommends that DEF's proposed changes to the LS-1 rate schedule and lighting service contract, as shown in Attachment A, be approved. The revised tariffs should become effective on May 8, 2018.

Issue 2: Should this docket be closed?

Recommendation: If a protest is filed within 21 days of the issuance of the order, the tariffs should remain in effect, with any revenues held subject to refund, pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order. (Crawford)

Staff Analysis: If a protest is filed within 21 days of the issuance of the order, the tariffs should remain in effect, with any revenues held subject to refund, pending resolution of the protests. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order.

DUKE ENERGY.

SECTION NO. VI
~~TENTH~~ ELEVENTH REVISED SHEET NO. 6.283
CANCELS ~~NINTH~~ TENTH REVISED SHEET NO. 6.283

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 4)

III. Additional Facilities

BILLING TYPE

BILLING TYPE	Electrical Pole Receptacle [4]	
401	Single	$3.00 per unit
402	Double	$3.90 per unit

Notes to Per Unit Charges:

(1) Restricted to existing installations.
(2) Lumens output may vary with lamp configuration and age. Wattage ratings do not include ballast losses. Actual wattage may vary up to +/- 5 watts.
(3) Shown for information only. Energy charges are billed by applying the foregoing energy and demand charges to the total monthly kWh.
(4) Electric use permitted only during the period of October through January, only on poles designated by the Company. Energy charged separately. Customers must notify Company of installation of customer-owned receptacles prior to such installation.
(5) Special applications only.

Additional Charges:

Fuel Cost Recovery Factor:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105
Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fee:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

Minimum Monthly Bill:

The minimum monthly bill shall be the sum of the Customer Charge and applicable Fixture, Maintenance and Pole Charges.

Terms of Payment:

Bills rendered hereunder are payable within the time limit specified on bill at Company-designated locations.

Terms of Service:

Service under this rate schedule shall be for a minimum initial term of ten (10) years from the commencement of service and shall continue thereafter until terminated by either party by written notice sixty (60) days prior to termination. Upon early termination of service under this schedule, the customer shall pay an amount equal to the remaining monthly lease amount for the term of contract including Contribution in Aid of Construction ("CIAC") under Special Provision No.16, applicable Customer Charges and removal cost of the facilities.

Special Provisions:

1. The customer shall execute a contract on the Company's standard filed contract form for service under this rate schedule.
2. Where the Company provides a fixture or pole type other than those listed above, the monthly charges, as applicable shall be computed as follows:
   I. Fixture
      (a) Fixture Charge: 1.59% of the Company's average installed cost.
      (b) Maintenance Charge: The Company's estimated cost of maintaining fixture.

   II. Pole
      Pole Charge: 1.82% of installed cost.
3. The customer shall be responsible for the cost incurred to repair or replace any fixture or pole which has been willfully damaged. The Company shall not be required to make such repair or replacement prior to payment by the customer for damage.
4. Maintenance Service for customer-owned fixtures at charges stated hereunder shall be restricted to fixtures being maintained as of November 1, 1992. ~~For additional requests of the Company to perform maintenance of customer-owned fixtures, the Company may consider providing such service and bill the customer in accordance with the Company's policy related to "Work Performed for the Public."~~

(Continued on Page No. 6)

ISSUED BY: Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL

EFFECTIVE: ~~April 19, 2016~~

DUKE ENERGY.

SECTION NO. VI
~~FIFTH~~ SIXTH REVISED SHEET NO. 6.284
CANCELS ~~FOURTH~~ FIFTH REVISED SHEET NO. 6.284

RATE SCHEDULE LS-1
LIGHTING SERVICE
(Continued from Page No. 5)

Special Provisions: (Continued)

5. kWh consumption for Company-owned fixtures shall be estimated in lieu of installing meters. kWh estimates will be made using the following formula:

$$\text{kWh} = \frac{\text{Unit Wattage (including ballast losses) x 350 hours per month}}{1{,}000}$$

6. kWh consumption for customer-owned fixtures shall be metered. Installation of customer-owned lighting facilities shall be provided for by the customer. ~~The Company may consider installing customer-owned lighting facilities and will bill the customer in accordance with the Company's policy related to "Work Performed for the Public."~~ Any costs incurred by the Company to provide for consolidation of existing lighting facilities for the purpose of metering shall be at the customer's expense.

7. No Pole Charge shall be applicable for a fixture installed on a company-owned pole which is utilized for other general electrical distribution purposes.

8. The Company will repair or replace malfunctioning lighting fixtures maintained by the Company in accordance with Section 768.1382, Florida Statutes (2005).

9. For a fixture type and/or pole type restricted to existing installations and requiring major renovation or replacement, the fixture and/or pole shall be replaced by an available similar non-restricted fixture and/or pole ~~of the customer's choosing~~ and the customer shall commence being billed at its appropriate rate. Where the customer requests the continued use of the same fixture type and/or pole type for appearance reasons, the Company will attempt to provide such fixture and/or pole and the customer shall commence being billed at a rate determined in accordance with Special Provision No. 2 for the cost of the renovated or replaced fixture and/or pole.

10. The customer will be responsible for trimming trees and other vegetation that obstruct the light output from fixture(s) or maintenance access to the facilities.

11. After December 31, 1998, all new leased lighting shall be installed on poles owned by the Company.

12. Alterations to leased lighting facilities requested by the customer after date of installation (i.e. redirect, install shields, etc.), will be billed to the customer in accordance with the Company's policy related to "Work Performed for the Public".

13. Service for street or area lighting is normally provided from existing distribution facilities. Where suitable distribution facilities do not exist, it will be the customer's responsibility to pay for necessary additional facilities. Refer to Section III, paragraph 3.01 of the Company's General Rules and Regulations Governing Electric Service to determine the ~~Contribution in Aid of Construction~~ CIAC owed by the customer.

14. Requests for exchanging facilities, upgrades, relocations, removals etc. are subject to Section III, paragraph 3.05, of the Company's General Rules and Regulations Governing Electric Service.

15. For available LEDs, the customer may opt to make an initial, one-time Contribution in Aid of Construction payment of 50% of the installed cost of fixtures rated greater than 200 Watts and/or poles other than standard wood poles, to reduce the Company's installed cost. If a customer chooses this option, the monthly fixture and/or pole charge shall be computed as the reduced installed cost times the corresponding monthly percentage in 2.I.(a) and/or 2.II above.

16. As an alternative to making an initial one-time CIAC payment to extend distribution facilities to render lighting service, as referenced in Special Provision No. 13, the customer may elect to pay a monthly fee of 1.59% of the calculated CIAC amount.

ISSUED BY: Javier J. Portuondo, Managing Director Rates & Regulatory Strategy – FL

EFFECTIVE: ~~January 5, 2016~~

DUKE ENERGY

SECTION NO. VII
SEVENTH~~SIXTH~~ REVISED SHEET NO. 7.110
CANCELS SIXTH~~FIFTH~~ REVISED SHEET NO. 7.110

LIGHTING SERVICE CONTRACT

ACCOUNT NUMBER
WORK ORDER NUMBER
DEF CONTACT

CUSTOMER NAME: ______________________________

SERVICE LOCATION(S):______________________________
(Street address, city/county, Company account number if established)

This Lighting Service Contract ("Contract") is hereby entered into this __________ day of ________________, 20 __ , between Duke Energy Florida, LLC~~Inc.~~ (hereinafter called the Company) and ______________________________ (hereinafter referred to as the "Customer") for lighting service at the above location(s). The Customer agrees to receive and pay for lighting service from the Company in accordance with the rates, terms and provisions of the Company's Rate Schedule LS-1, or its successor, as the same is on file with the Florida Public Service Commission (FPSC) and as may be amended and subsequently filed with the FPSC. To the extent there is any conflict between this Contract and the Lighting Service Rate Schedule, the Lighting Rate Schedule shall control.

The Customer further understands that service under this rate shall be for an initial term of **ten (10) years** and shall continue hereafter until terminated by either party upon written notice sixty (60) days prior to termination.

The Company shall install the following facilities (hereinafter called the Facilities):

Fixture Type and Number Installed:

Pole Type and Number Installed:

Additional facilities:

(Continued in Next Page)

ISSUED BY: Javier J. Portuondo, Managing ~~Manager,~~ Director, Rates & Regulatory Strategy – FL **Form LS-1**
EFFECTIVE: ~~April 29, 2013~~

Rate per Month:

The monthly charges consist of the items below. These charges may be adjusted subject to review and approval by the Florida Public Service Commission.

Customer Charge	
Pole Charge	
Light Fixture Charge	
Light Fixture Maintenance Charge	
Energy and Demand ~~Charge~~ :Charge:	
Non-fuel Energy Charge	
Plus the Cost Recovery Factors listed in Rate Schedule BA-1, Billing Adjustments**, except the Fuel Cost Recovery Factor and Asset Securitization Charge Factor:	See Sheet No. 6.105 and 6.106
Fuel Cost Recovery Factor **:	See Sheet No. 6.105
Asset Securitization Charge Factor:	See Sheet No. 6.105

***Charges are normally revised on an annual basis.*

Additional Charges:

Certain additional charges may also apply to the installation.

Gross Receipts Tax Factor:	See Sheet No. 6.106
Right-of-Way Utilization Fees:	See Sheet No. 6.106
Municipal Tax:	See Sheet No. 6.106
Sales Tax:	See Sheet No. 6.106

THE CUSTOMER AGREES:

1. To purchase from the Company all of the electric energy used for the operation of the Lighting System.
2. To be responsible for paying, when due, all bills rendered by the Company pursuant to the Company's currently effective Lighting Rate Schedule LS-1, or its successor, for facilities and service provided in accordance with this Contract.
3. To be responsible for trimming trees that may either obstruct the light output from fixture(s) or that obstruct maintenance access to the facilities.

IT IS MUTUALLY AGREED THAT:

4. Requests for exchanging facilities, upgrades, relocations, etc. are subject to Section III, paragraph 3.05, of the Company's General Rules and Regulations Governing Electric Service.
5. The Company does not guarantee continuous lighting service and will not be liable for damages for any interruption, deficiency or failure of service, and reserves the right to interrupt service at any time for necessary repairs to lines or equipment. Nothing in this Contract is intended to benefit any third party or to impose any obligation on the Company to any such third party.
6. Installation shall be made only when, in the judgment of the Company, the location and the type of the facilities are, and will continue to be, easily and economically accessible to the Company's equipment and personnel for both construction and maintenance. In the event the Customer or its contractor, subcontractor or other agent changes the grading, which requires the Company to move its facilities or otherwise incur costs to ensure compliance with applicable code requirements, Customer shall compensate the Company for all such costs incurred by the Company to comply with any applicable code requirements. In the event Customer fails to pay the Company within 30 days of the completion of such work, Customer shall pay the Company any amounts owing the Company, including interest and any attorneys and other fees and costs the Company incurs to collect any amounts owed to the Company.
7. Modification of the facilities provided by the Company under this Contract may only be made through the execution of a written amendment to this Contract.

(Continued in Next Page)

8. The Company will, at the request of the Customer, relocate the lighting facilities covered by this Agreement, if provided sufficient rights-of-way or easements to do so. The Customer shall be responsible for the payment of all costs associated with any such Customer-requested relocation of the Company's lighting facilities.

9. The Company may, at any time, substitute for any luminaire/lamp installed hereunder another luminaire/lamp which shall be of at least equal illuminating capacity and efficiency.

10. The Customer agrees to take responsibility for the cost incurred to repair or replace any fixture or pole which has been willfully damaged. The Company shall not be required to make such repair or replacement prior to payment by the Customer for damage.

11. The Company will repair or replace malfunctioning lighting fixtures maintained by the Company in accordance with Section 768.1382, Florida Statutes (2005).

12. This Contract shall be for a term of ten (10) years from the date of initiation of service. The date of initiation of service shall be defined as the date the first lights are energized~~. At the end of the term of service, a new Contract will be required~~.

13. Should the Customer fail to pay any bills due and rendered pursuant to this Contract or otherwise fail to perform the obligations contained in this Contract, said obligations being material and going to the essence of this Contract, the Company may cease to supply electric energy or service until the Customer has paid the bills due and rendered or has fully cured such other breach of this Contract. Service charges associated with the reconnection of service after disconnection for nonpayment or violation of Company or Commission Rules may be assessed for each lighting installation on an account. Any failure of the Company to exercise its rights hereunder shall not be a waiver of its rights. It is understood, however, that such discontinuance of the supplying of electric energy or service shall not constitute a breach of this Contract by the Company, nor shall it relieve the Customer of the obligation to perform any of the terms and conditions of this Contract.

14. If the Customer no longer wishes to receive service under this schedule, the Customer may terminate the Contract by giving the Company at least sixty (60) days advance written notice to the Company. Upon early termination of service, the Customer shall pay an amount equal to the remaining monthly customer charges, remaining Contribution in Aid of Construction ("CIAC"), if applicable, and remaining pole and fixture lease amounts for the term of the contract. The Customer will be responsible for the cost of removing the facilities.

15. In the event of the sale of the real property upon which the facilities are installed, or if the Customer's obligations under this Contract are to be assigned to a third party, upon the written consent of the Company , this Contract may be assigned by the Customer to the Purchaser or to the third party. No assignment shall relieve the Customer from its obligations hereunder until such obligations have been assumed by the Purchaser or third party and agreed to by the Company.

16. This Contract supersedes all previous contracts or representations, either written, oral or otherwise between the Customer and the Company with respect to the facilities referenced herein and constitutes the entire Contract between the parties. This Contract does not create any rights or provide any remedies to third parties or create any additional duty, obligation or undertakings by the Company to third parties.

17. This Contract shall inure to the benefit of, and be binding upon the successors and assigns of the Customer and the Company.

18. This Contract is subject to the Company's Tariff for Retail Service, or as they may be hereafter revised, amended or supplemented. In the event of any conflict between the terms of this Contract and the provisions of the Company's Tariff for Retail Services, the provisions of the Company's Tariff for Retail Service and FPSC Rules shall control, or as they may be hereafter revised, amended or supplemented.

(Continued in Next Page)

19. The obligation to furnish or purchase service shall be excused at any time that either party is prevented from complying with this Contract by strikes, lockouts, fires, riots, acts of God, the public enemy, governmental or court actions, lightning, hurricanes, storms, floods, inclement weather that necessitates extraordinary measures and expense to construct facilities and/or maintain operations, or by any other cause or causes not under the control of the party thus prevented from compliance, and the Company shall not have the obligation to furnish service if it is prevented from complying with this Contract by reason of any partial, temporary or entire shut-down of service which, in the sole opinion of the Company, is reasonably necessary for the purpose of repairing or making more efficient all or any part of its generating, transmission, distribution or other electrical equipment.

20. In no event shall the Company, its parent corporation, affiliate corporations, officers, directors, employees, agents, and contractors or subcontractors be liable to the Customer, its employees, agents or representatives, for any incidental, indirect, special, consequential, exemplary, punitive or multiple damages resulting from any claim or cause of action, whether brought in contract, tort (including, but not limited to, negligence or strict liability), or any other legal theory.

IN WITNESS WHEREOF, the parties hereby caused this Contract to be executed ~~in triplicate~~ by their duly authorized representatives to be effective as of the day and year first written above.

Charges and Terms Accepted:

______________________________ Customer (Print or type name of Organization)	DUKE ENERGY FLORIDA, LLC~~INC.~~
By:______________________________ (Signature)	By:______________________________ (Signature)
______________________________ (Print or type name)	______________________________ (Print or type name)
Title:______________________________	Title:______________________________

Item 6

FILED 4/26/2018
DOCUMENT NO. 03226-2018
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: April 26, 2018

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Merryday, Draper) EJD THM PDG8 WT
Office of the General Counsel (Trierweiler) CM

RE: Docket No. 20180043-GU – Petition for approval of area extension plan rate extension agreement with United States Sugar Corporation, by Florida City Gas.

AGENDA: 05/08/18 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On February 20, 2018, Florida City Gas (FCG or utility) filed a petition for approval of an Area Extension Plan Rate Extension Agreement (AEP Agreement) with United States Sugar Corporation (U.S. Sugar). The extension of the utility's distribution facilities to serve U.S. Sugar and the surrounding area is known as the Glades AEP Project.

The Area Extension Plan (AEP) tariff is designed to provide FCG with an optional method to recover its capital investment to provide natural gas service to customers in a discrete geographical area who do not have gas service available.[1] The AEP tariff provides for the determination of a surcharge based on the required investment and the projected gas sales to customers located in the geographical area. The surcharge is applied on a per therm basis over a

[1] Order No. PSC-95-0506-FOF-GU, issued April 24, 1995, in Docket No. 950206-GU, *In re: Petition for approval of tariffs governing extension of facilities by City Gas Company of Florida.*

ten year amortization period in addition to all other tariffed charges. The AEP tariff specifies the formula to calculate the charge; the utilization of the tariff itself does not require Commission approval.

The AEP tariff provides for a surcharge recalculation on the third anniversary of facilities being placed in service. The customers on the Glades AEP Project began taking service in 2012, therefore, a true-up was to occur in 2015. However, significant problems led FCG to request, in October 2015, that the Commission approve a variance to the AEP tariff to provide relief to customers on the Glades AEP Project. The Commission approved FCG's request in 2015 in Order No. PSC-16-0066-PAA-GU (2015 Order).[2]

FCG stated that it has used the AEP tariff mechanism for eight projects since its 1995 implementation, and the AEP has proved helpful to the utility and customers that may have otherwise been unable to receive service. However, the primary customer on the Glades AEP Project, U.S. Sugar, continues to face unique and significant challenges and a surcharge recalculation pursuant to the 2015 Order may interfere with the economic wellbeing and development in the area. Therefore, FCG filed the instant petition. On March 22, April 6, and April 16, 2018, FCG responded to staff's data requests. On April 18, 2018, FCG filed a supplemental amendatory petition to clarify that the AEP surcharge will terminate in 2024 for all Glades AEP Project customers except for U.S. Sugar as provided for in the AEP Agreement. The AEP Agreement is attached to the recommendation as Attachment A (Exhibit A to the AEP Agreement is not attached as it contains confidential information). The Commission has jurisdiction over this matter pursuant to Section 366.06, Florida Statutes.

[2] Order No. PSC-16-0066-PAA-GU, issued March 2, 2016, in Docket No. 150232-GU, *In re: Petition for Approval of Variance to Delay Area Extension Program True-Up and Extend Amortization Period by Florida City Gas*

Discussion of Issues

Issue 1: Should the Commission approve the AEP Agreement and FCG's request for a variance from the AEP tariff for the Glades AEP Project?

Recommendation: Yes, the Commission should approve the AEP Agreement and FCG's request for a variance from the AEP tariff for the Glades AEP Project. (Merryday)

Staff Analysis: In November 2012, when the customers on the Glades AEP Project first began taking service, the surcharge was calculated to be $0.241 per therm. This assumed reasonably forecasted natural gas usage and an amortization period of ten years. At the time of the original third year true-up, the utility determined that, to keep the amortization period to ten years, the new surcharge would have to be $0.515 per therm. This was the result of unanticipated environmental issues, fewer new customers taking service than expected, and a citrus canker blight which caused U.S. Sugar to use significantly less natural gas than predicted. To reduce the financial strain on customers and encourage economic growth, FCG asked the Commission to delay the surcharge recalculation by two years, until October 2017, with the amortization period extending through October of 2024. The Commission approved the proposal and the rate remained $0.241 per therm.

In late 2017, the utility performed the true-up calculations required by the 2015 Order, but determined that extenuating factors have continued to impede natural gas usage and would make the recalculated rate increase to $0.629 per therm. FCG explained that the December 2017 through May 2018 citrus harvesting and processing season was on track to be the first productive year after more than a decade of disease, but Hurricane Irma destroyed up to 89 percent of the crops where U.S. Sugar sourced its fruit. The utility also notes that primarily the fruit, and not the trees, were damaged and citrus production should increase next season.

Being mindful of the significant economic impacts such a rate increase would have on the Glades AEP Project customers, including the largest industrial customer in the Glades project, U.S. Sugar, FCG proposed the special AEP Agreement with U.S. Sugar and revised AEP surcharges for all Glades customers. While the AEP Agreement is between the utility and U.S. Sugar and any affiliates (for whom the project was primarily designed), it provides benefits to all customers on the Glades AEP Project. The AEP Agreement and the revised AEP surcharges to all other Glades customers are discussed below.

Glades AEP Agreement

The AEP Agreement includes the following elements:

- The AEP surcharge will be set at $0.301 per therm instead of $0.629 (a reduction of $0.328 per therm).
- In exchange for the reduced rate, U.S. Sugar agrees to continue taking service for its Southern Gardens citrus processing facility (plant) and paying the AEP surcharge through November 2027 or until it has repaid 87.13 percent of the contribution in aid of construction (CIAC). In the event that a balance remains at the end of November 2027 or

that U.S. Sugar terminates service at its plant early, U.S. Sugar will submit the remainder of the CIAC to FCG within 45 days.

- U.S. Sugar's affiliates and subsidiaries agree to continue taking service and paying the AEP surcharge after the amortization period ends in 2024. Thereafter, if natural gas is no longer an economically viable option, U.S. Sugar's affiliates and subsidiaries, excluding the plant, may provide reasonable documentation to that effect in order to cease taking service. U.S. Sugar's affiliates and subsidiaries must provide at least 60 days notice to do so.

- Glades AEP surcharge recalculations will occur in November 2020 and November 2022, with one subsequent recalculation occurring upon U.S. Sugar demonstrating a six percent increase in annual natural gas consumption thereafter.

Other Glades AEP Customers

For the remaining customers on the Glades AEP Project, the AEP surcharge will also be set at \$0.301 per therm (instead of the recalculated rate of \$0.629 per therm). Similar to the AEP Agreement discussed above, AEP surcharge recalculations will occur in November 2020 and November 2022, with one subsequent recalculation occurring upon U.S. Sugar's demonstrated six percent increase of natural gas consumption after November 2022. The utility explained that with U.S. Sugar being the largest customer in the Glades AEP Project, a six percent increase in consumption by U.S. Sugar would result in a reduction in the AEP surcharge, therefore benefitting all customers. As provided for in the 2015 Order, the AEP surcharge assessed to the Glades AEP Project customers will terminate in October 2024.

FCG stated that it has been able to contact 36 of 38 customers on the Glades AEP Project regarding the recalculated AEP rate. In response to Staff's First Data Request, FCG claims that these customers have accepted the recalculated AEP rate. For the remaining two customers, FCG states that a representative left contact information.

Conclusion

The utility states that the proposed lower AEP surcharge will reduce recovery on the Glades AEP Project by approximately \$5 million. However, according to the utility, the \$5 million under-recovery will not affect the general body of rate payers and any unrecovered amount is a risk to the utility's shareholders.

In FCG's recent rate case, the Commission approved changes to the AEP tariff that provides for true-ups on the third, fifth, seventh, and ninth anniversaries of the date when each AEP project goes into service.[3] The utility stated that this will prevent spikes in AEP rates and allow for gradual adjustments over time, if needed. In its response to Staff's Second Data Request, FCG indicated that these true-up requirements will not apply to the Glades AEP Project.

FCG's proposal will benefit U.S. Sugar, the large industrial customer in the Glades Project area, who is facing unique economic challenges. The proposal will also give relief to the other

[3] Order No. PSC-2018-0190-FOF-GU, issued April 20, 2018, in Docket No. 20170179-GU, *In re: Petition for rate increase by Florida City Gas*

customers by providing for a lower AEP rate. Staff therefore recommends that the Commission approve FCG's request for the AEP Agreement and a variance from the AEP tariff.

Issue 2: Should this docket be closed?

Recommendation: If no protest is filed by a person whose substantial interests are affected within 21 days of the issuance of the Order, this docket should be closed upon the issuance of a Consummating Order. (Trierweiler)

Staff Analysis: If no protest is filed by a person whose substantial interests are affected within 21 days of the issuance of the Order, this docket should be closed upon the issuance of a Consummating Order.

AREA EXTENSION PLAN RATE EXTENSION AGREEMENT

THIS RATE EXTENSION AGREEMENT ("Agreement") is entered into by and between Pivotal Utility Holdings, Inc. d/b/a Florida City Gas, a natural gas local distribution company ("LDC") and a subsidiary of Southern Company Gas, hereinafter referred to as (**"FCG"**), and United States Sugar Corporation ("USSC"), hereinafter referred to as (**"Customer"**) (jointly, **"Parties"**).

WITNESSETH:

WHEREAS, FCG operates facilities for the distribution of natural gas in the State of Florida; and

WHEREAS, Customer owns and operates a citrus processing facility at 1820 County Road 833, Clewiston, Florida (the "Plant");

WHEREAS, FCG constructed its Glades pipeline to serve Customer and currently provides natural gas service to Customer, as well as other entities, via the Glades pipeline; and

WHEREAS, when the Glades pipeline was placed into service, the booked investment exceeded the Maximum Allowable Construction Cost ("MACC"), resulting in a contribution in aid of construction to be recovered consistent with FCG's Florida Public Service Commission ("FPSC") tariff; and

WHEREAS, the cost of the installation of the Glades pipeline is $17,766,616, which results in the amount to be recovered from the Customer and other entities served by the Glades pipeline being $13,159,111, plus carrying a cost of $3,332,088, for a total of $16,491,199 (such total, the "Contribution");

WHEREAS, the Parties acknowledge that the Contribution may vary depending upon consumption of natural gas by customers on the Glades pipeline; and

WHEREAS, recovery of the Contribution has been addressed by application of FCG's tariffed Area Extension Plan ("AEP"), which provides for calculation of a surcharge amount to be applied over a 10-year period to recover FCG's capital investment to provide natural gas service to customers to a discrete geographic area, which area, in this instance, is referred to as the "Glades Project"; and

WHEREAS, FCG's tariff provides that the AEP surcharge may only be recalculated, if at all, at Year 3 of the amortization period based upon updated costs and therm usage; and

WHEREAS, in 2015, FCG petitioned the FPSC for approval, and was allowed, to defer the recalculation of the AEP charge for a period of two years and to extend the project amortization period from 10 years to 12 years through November 2024 ("Amortization Period"), because the

AEP surcharge for Customer and others in the Glades Project was projected to increase from $0.241 per therm to $0.629 per therm; and

WHEREAS, the extension of the AEP recalculation ended October 31, 2017, and as such, the recalculated, higher AEP surcharge would be assessed to Customer and others served by the Glades pipeline with the December 2017 bill; and

WHEREAS, an increase in AEP charge would have significant negative consequences to Customer and others in the Glades Project as acknowledged in Order No. PSC-2016-0066-PAA-GU; and

WHEREAS, Customer's operation has significant economic consequences for Clewiston and the surrounding areas; and

WHEREAS, the FPSC has recognized the benefits to the general body of ratepayers of retaining large customers on LDC systems; and

WHEREAS, retention of Customer as contemplated in this Agreement will have no adverse impacts to FCG's ratepayers nor will it put the ratepayers at increased risk;

NOW, THEREFORE, in consideration of the premises and the mutual covenants and agreements herein contained, and other good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, and intending to be bound hereby, the Parties do therefore agree as follows:

1.0 Surcharge Amount. Effective January 31, 2018, ("Effective Date"), the AEP charge for the Glades Project will be set at $0.301 per therm for all customers, which [redacted] consistent with the model contained in Exhibit A as attached hereto and incorporated herein by reference.

2.0 Continuation of AEP Surcharge. This Agreement shall remain in effect from the Effective Date through the end of November 2027. At the end of the 12-year Amortization Period, Customer and its affiliates, including, but not limited to the Plant, which are being served by the Glades pipeline, will continue to be assessed the $0.301 per therm AEP charge per Exhibit A for the remainder of the Term of this Agreement, except as otherwise contemplated in Section 4.0 below.

3.0 Release of Non-Affiliates. The Parties agree and acknowledge that, at the end of the 12-year Amortization Period, the AEP charge will be eliminated for all other customers served by the Glades pipeline that are not otherwise affiliated with USSC, in accordance with FCG's tariff and the FPSC's Order No. PSC-2016-0066-PAA-GU.

4.0 Recalculation of AEP Charge. The AEP charge will be recalculated in November 2020 and November 2022 to capture changes in annual consumption only. Each recalculation [redacted] consistent with FCG's AEP tariff. Subsequent to the recalculation in 2022 through the end of the Term of this Agreement, Customer may request one additional recalculation of the AEP, which shall be implemented by FCG upon demonstration by Customer of a 6% overall increase in natural gas consumption by Customer from the FCG system occurring during the period subsequent to the year 9 recalculation (November 2022) and the date of the request for the additional recalculation.

5.0 Service Commitment.

5.1 Southern Gardens. Customer commits that Plant will either maintain service with FCG for, at a minimum, the period of time necessary for FCG to fully recover the Contribution or, consistent with Exhibit A, Customer will pay the then outstanding balance for AEP investments to serve their facilities, excluding the ROE, within 45 days of termination of service by Customer.

5.2 Affiliates and Subsidiaries. Customer shall cause all other USSC affiliates and subsidiaries served by the Glades pipeline to maintain natural gas service with FCG as long as natural gas service is an economically viable option. In the event that Customer determines that natural gas is no longer an economically viable option for the USSC affiliates and subsidiaries, Customer shall provide FCG with reasonable and verifiable documentation supporting Customer's conclusion that natural gas service is no longer an economically viable option for any or all of the USSC affiliates and subsidiaries and shall provide no less than 60 days' notice of intent to suspend or terminate service. Consistent with Section 5.1 above, this Section 5.2 shall not apply to Plant.

5.3 Early Termination of Obligation. Customer may terminate its obligations hereunder prior to the end of the Term by submitting, in full, payment for the remainder of the amount of its obligation hereunder, which is 87.13% of the Contribution. The Parties recognize and agree that the Contribution will change as payments are made consistent with this Agreement and FCG's tariff, and if natural gas consumption on the Glades pipeline changes.

6.0 Definitions: For purposes of this Agreement, "economically viable" shall be construed as meaning that the sum total cost of utilizing natural gas a fuel source is equal to, or less than, the sum total cost of utilizing another fuel source, including the cost of any new or revised equipment installations necessary to utilize a fuel source other than natural gas.

7.0 Governmental Authorizations; Compliance with Law. This Agreement shall be subject to all valid applicable state, local and federal laws, orders, directives, rules and regulations of any governmental body, agency or official having jurisdiction over this

Agreement and the provision of natural gas service hereunder. FCG and Customer shall comply at all times with all applicable federal, state, municipal, and other laws, ordinances and regulations. FCG and Customer shall proceed with diligence to file any necessary applications with any governmental authorities for any authorizations necessary to carry out its obligations under this Agreement. In the event this Agreement or any provisions herein shall be found contrary to or in conflict with any applicable law, order, directive, rule or regulation, the latter shall be deemed to control, but nothing in this Agreement shall prevent either party from contesting the validity of any such law, order, directive, rule, or regulation, nor shall anything in this Agreement be construed to require either party to waive its respective rights to assert the lack of jurisdiction of any governmental agency, other than the FPSC, over this Agreement or any part thereof. As used herein, "Governmental Authority" shall mean any United States federal, state, local, municipal or other government; any governmental, regulatory or administrative agency, court, commission or other authority lawfully exercising or entitled to exercise any administrative, executive judicial, legislative, police, regulatory or taxing authority or power; and any court or governmental tribunal.

8.0 Applicable Law and Venue. This Agreement and any dispute arising hereunder shall be governed by and interpreted in accordance with the laws of the State of Florida. The venue for any action, at law or in equity, commenced by either party against the other and arising out of or in connection with this Agreement shall be before the FPSC or in a court of the State of Florida otherwise having jurisdiction.

9.0 Counterparts. This Agreement may be executed in counterparts, all of which taken together shall constitute one and the same instrument and each of which shall be deemed an original instrument as against any party who has signed it.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their duly authorized officers or representatives effective as of the date first written above.

COMPANY	CUSTOMER
Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	United States Sugar Corporation
By:	By:
Name: Carolyn Bermudez	Name: Dan Casper
Title: Vice President	Title: Vice President - Citrus

(To be attested by the corporate secretary if not signed by an officer of the company)

Attested By:________	Attested By:________
Title:________	Title:________
Date:________	Date:________

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: April 26, 2018

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Bethea, Hudson) SH TB CS PN MC
Division of Accounting and Finance (Cicchetti)
Office of the General Counsel (Crawford)

RE: Docket No. 20180100-WS – Application for approval of tariff for the gross-up of CIAC for water rates in Lee County and wastewater rates in Pasco County, by Ni Florida, LLC.

AGENDA: 05/08/18 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 06/18/18 (60-Day Suspension Date)

SPECIAL INSTRUCTIONS: None

Case Background

Ni Florida, LLC (Ni Florida or utility) is a Class A utility providing service to approximately 745 water connections in Lee County and 2,757 wastewater connections in Pasco County. The utility reported in its 2017 annual report operating revenues in the amount of $292,211 for water and $2,282,516 for wastewater. The utility did not collect any contributions in aid of construction (CIAC) for 2017.

On April 17, 2018, the utility filed an application for approval of a tariff to allow for gross-up of CIAC. As discussed in Issue 1 below, the utility indicated that the change in tax law may cause it to risk the loss of its opportunity to earn a reasonable return on its used and useful property if it is not allowed to collect the tax impact on receipt of CIAC. This recommendation addresses the utility's request for approval of gross-up tariffs related to 2018 changes in the federal tax code.

Any potential refund related to the change in the federal tax rate currently embedded in the utility's rates is outside of this recommendation and will be addressed in the generic Docket No. 20180013-PU.[1] The Commission has jurisdiction pursuant to Sections 367.081 and 367.091, Florida Statutes (F.S.).

[1] Docket No. 20180013-PU, *In re: Petition to establish generic docket to investigate and adjust rates for 2018 tax savings, by Office of Public Counsel.*

Discussion of Issues

Issue 1: Should Ni Florida's request for approval of a tariff to allow the gross-up of CIAC be approved?

Recommendation: Yes, the tariffs filed on April 17, 2018 should be approved. The utility should provide notice to all persons in the service areas included in the application who have filed a written request for service or who have been provided a written estimate for service within the 12 calendar months prior to the month the application was filed. The approved gross-up charges should be effective for connections made on or after the stamped approval date on the tariff sheets. The utility should provide proof of noticing within 10 days of rendering its approved notice. (Bethea, Hudson, Cicchetti)

Staff Analysis: Effective January 1, 2018, the Federal Tax Cuts and Jobs Act amended Section 118 of the Internal Revenue Code. Prior to the amendments, CIAC was exempt from taxable gross income for water and wastewater utilities. As a result of the amendments, both cash and property CIAC are now taxable gross income for water and wastewater utilities. In recognition of this change in the tax law, the Commission has opened Docket No. 20180013-PU, *In re: Petition to establish a generic docket to investigate and adjust rates for 2018 tax savings by Office of Public Counsel* to address the potential rate impacts on regulated electric, gas, water, and wastewater utilities.

A similar law, the Tax Reform Act of 1986, became effective in 1987.[2] In Docket No. 19860184-PU, the Commission found that it was appropriate to allow water and wastewater utilities to recover the tax on CIAC from the contributor, including the tax associated with the additional tax that would also become taxable income. For those utilities that were approved to collect the gross-up on CIAC, the gross-up amounts collected were held subject to refund and were evaluated on a case-by-case basis as to whether any refunds were subsequently required.

On April 17, the utility filed a tariff (Attachment A) to gross-up cash service availability charges and property contributions to recover the federal and state corporate income taxes associated with those contributions. According to the utility, Ni Florida could risk loss of its opportunity to earn a reasonable return on its property used and useful in the public service if it is not allowed to collect the tax impact on receipt of CIAC.[3]

The tariff recognizes that, for depreciable property, depreciation expense is tax deductible and the utility's tax liability will be reduced by depreciation claimed for tax purposes. The proposed tariff is mathematically the same, regarding the gross-up for taxes, as the tariff approved by the Commission following the hearing in Docket No. 19860184-PU.[4] Because the proposed tariff accurately depicts the utility's expected tax expense associated with CIAC, staff believes no further Commission action would be required once the gross-up formula has been approved.

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[2] The amendment was repealed in 1996.

[3] According to the 2017 Annual Report, Ni Florida collected approximately $1,453,329 in cash and property CIAC.

[4] Order No. 23541, issued October 1, 1990, in Docket No. 860184-PU, *In re: Request by Florida Waterworks Association for investigation of proposed repeal of Section 118(b), Internal Revenue Code [Contributions-in-aid-of-construction].*

Staff notes that in Order No. 23541 in Docket No. 19860184-PU, the Commission required a reconciliation of CIAC tax collected to taxes paid. Staff does not believe a reconciliation of tax collected on CIAC to taxes paid should be required for two reasons. First, the proposed formula more appropriately tracks the potential tax liability associated with the collection of CIAC. Second, expenses approved in base rates are not typically subject to reconciliation. For example, the utility's revenue requirement is grossed-up for expected taxes and expected tax expense is included in rates but there is no after-the-fact proceeding to reconcile taxes actually paid with tax expense allowed in case the utility experienced a loss and paid no taxes. Consequently, staff believes no after-the-fact proceeding is warranted to compare allowed tax expense for CIAC to actual tax expense and, therefore, no corporate undertaking is necessary.[5]

Based on the above, staff recommends that the tariffs should be approved. The approved gross-up charges should be effective for connections made on or after the stamped approval date on the tariff sheets. The utility should provide notice to all persons in the service areas included in the application who have filed a written request for service or who have been provided a written estimate for service within the 12 calendar months prior to the month the application was filed. The utility should provide proof of noticing within 10 days of rendering its approved notice.

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[5] Staff's recommendation is consistent with the Commission's vote at the April 20,2018 Agenda Conference with respect to Docket No. 20180042-WS, *In re: Application for approval of tariff for the gross-up of CIAC in Martin County, by Indiantown Company, Inc.*, and Docket No. 20180059-WS, *In re: Application for approval of tariff for the gross-up of CIAC in Escambia County, by Peoples Water Service Company of Florida, Inc.*

Issue 2: Should this docket be closed?

Recommendation: If a protest is filed by a substantially affected person within 21 days of issuance of the order, the tariffs should remain in effect, with any revenues held subject to refund, pending resolution of the protest. If no timely protest is filed, the order should become final upon the issuance of a consummating order. However, the docket should remain open to allow staff to verify that the appropriate notice has been filed by the utility and approved by staff. Once the utility has provided proof of noticing, the docket should be closed administratively. (Crawford)

Staff Analysis: If a protest is filed by a substantially affected person within 21 days of issuance of the order, the tariffs should remain in effect, with any revenues held subject to refund, pending resolution of the protest. If no timely protest is filed, the order should become final upon the issuance of a consummating order. However, the docket should remain open to allow staff to verify that the appropriate notice has been filed by the utility and approved by staff. Once the utility has provided proof of noticing, the docket should be closed administratively.

NI FLORIDA, LLC
WATER TARIFF

FIRST REVISED SHEET NO. 19.0
CANCELS ORIGINAL SHEET NO. 19.0

Income Taxes Related to Cash and Property Contributions In Aid of Construction

The utility may gross-up cash service availability charges and property contributions in aid of construction in order to recover the federal and state corporate income taxes associated with these contributions. The formula to be used to gross-up cash service availability charges and contributed property are as follows:

TAX IMPACT= Full Gross Up:

Depreciable Plant:

For utilities using straight-line depreciation for tax purposes, the gross-up formula shall be: (CP – (CP * (1/TL) * .5)) * (CTR/ (1-CTR))

For utilities using an accelerated rate of depreciation for tax purposes, the gross-up formula shall be: (CP – ((CP * AR) * .5)) * (CTR/ (1-CTR))

Land (and Cash): (CL * CTR) * (CTR/(1-CTR))

Where:

CP = Contributed Plant

TL = Tax Life of Contributed Plant

AR = First Year Accelerated Depreciation Rate for Tax Purposes

CTR = Combined Federal (FT) and State (ST) Income Tax Rate. ST+FT (1-ST)

CL = Contributed Land (and Contributed Cash)

EFFECTIVE DATE:

TYPE OF FILING: Tariff Filing

Michael J. Ashford
ISSUING OFFICER

Regulatory Director
TITLE

NI FLORIDA, LLC
WASTEWATER TARIFF

ORIGINAL SHEET NO. 18.1

Income Taxes Related to Cash and Property Contributions In Aid of Construction

The utility may gross-up cash service availability charges and property contributions in aid of construction in order to recover the federal and state corporate income taxes associated with these contributions. The formula to be used to gross-up cash service availability charges and contributed property are as follows:

TAX IMPACT= Full Gross Up:

Depreciable Plant:

For utilities using straight-line depreciation for tax purposes, the gross-up formula shall be: (CP – (CP * (1/TL) * .5)) * (CTR/ (1-CTR))

For utilities using an accelerated rate of depreciation for tax purposes, the gross-up formula shall be: (CP – ((CP * AR) * .5)) * (CTR/ (1-CTR))

Land (and Cash): (CL * CTR) * (CTR/(1-CTR))

Where:

CP = Contributed Plant

TL = Tax Life of Contributed Plant

AR = First Year Accelerated Depreciation Rate for Tax Purposes

CTR = Combined Federal (FT) and State (ST) Income Tax Rate. ST+FT (1-ST)

CL = Contributed Land (and Contributed Cash)

EFFECTIVE DATE:

TYPE OF FILING: Tariff Filing

Michael J. Ashford
ISSUING OFFICER

Regulatory Director
TITLE

Item 8

FILED 4/26/2018
DOCUMENT NO. 03235-2018
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: April 26, 2018

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (Thompson, Ellis, King, Wright)
Division of Accounting and Finance (Barrett, Cicchetti)
Division of Economics (Bryant, Higgins, McNulty, Wu)
Office of the General Counsel (Dziechciarz, Murphy)

RE: Docket No. 20170266-EC – Petition to determine need for Seminole combined cycle facility, by Seminole Electric Cooperative, Inc.

Docket No. 20170267-EC – Joint petition for determination of need for Shady Hills combined cycle facility in Pasco County, by Seminole Electric Cooperative, Inc. and Shady Hills Energy Center, LLC.

AGENDA: 05/08/18 – Regular Agenda – Post-Hearing Decision – Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: Graham, Polmann, Clark

PREHEARING OFFICER: Clark

CRITICAL DATES: 05/8/18 – Commission vote. Petitioners waived 135 day order issuance requirement from Section 403.519(4), Florida Statutes, with understanding that staff intends to issue recommendation for consideration by the Commission at the 05/08/18 Agenda Conference.

SPECIAL INSTRUCTIONS: None

LIST OF ABBREVIATIONS & ACRONYMS

AE/Tierra	Advance Energy and Tierra Resource Consultants
BR	Brief
CAGR	Compound Annual Growth Rates
Commission	Florida Public Service Commission
CPP/CC Portfolio	Clean Power Plan/Combined Cycle Portfolio
CPVRR	Cumulative Present Value Revenue Requirement
CTG	Combustion Turbine Generators
DEF	Duke Energy Florida
DSM	Demand-Side Management
EIA	Energy Information Administration
EXH	Exhibit
F.A.C.	Florida Administrative Code
FEECA	Florida's Energy Efficiency Conservation Act
FPL	Florida Power & Light
F.S.	Florida Statutes
GWh	Gigawatt Hour
HRSG	Heat Recovery Steam Generator
Intervenors	Michael Tulk, Patrick Daly and Quantum Pasco Power, L.P.
LFS	Load Forecast Study
MW	Megawatt
NEL	Net Energy Load
NO_X	Nitrogen Oxide
NPV	Net Present Value

NYMEX	New York Mercantile Exchange
Petitioners	Seminole Electric Cooperative, Inc. and Shady Hills Energy Center, LLC
PPA	Power Purchase Agreement
PV	Photovoltaic
Quantum	Quantum Pasco Power, L.P.
RFP	Request for Proposals
SCCF	Seminole Combined Cycle Facility
Seminole	Seminole Electric Cooperative, Inc.
Seminole Facility	Seminole Combined Cycle Facility
SGS	Seminole Generating Station
Shady Hills	Shady Hills Energy Center, LLC
Shady Hills Facility	Shady Hills Combined Cycle Facility
SHCCF	Shady Hills Combined Cycle Facility
STG	Steam Turbine Generator
TECO	Tampa Electric Company
TR	Transcript

Case Background

On December 21, 2017, the petition for determination of need for the Seminole Combined Cycle Facility (Seminole Facility) was filed by Seminole Electric Cooperative, Inc. (Seminole) and the Joint Petition for Determination of Need for the Shady Hills Combined Cycle Facility (Shady Hills Facility) was filed by Seminole and Shady Hills Energy Center, LLC (Shady Hills) (collectively, Petitioners). The Seminole Facility is a proposed 1,122 megawatt (MW) (winter capacity) new natural gas fired 2x1 combined cycle generating unit to be located at Seminole's existing Seminole Generating Station (SGS) in Putnam County, Florida. This plant would utilize existing facilities, including transmission lines and SGS infrastructure. The Shady Hills Facility is a proposed 573 MW (winter capacity) new natural gas fired 1x1 combined cycle facility to be constructed, owned, and operated by Shady Hills in Shady Hills, Florida, adjacent to the existing Shady Hills power plant. This plant would provide all of its generating capacity to Seminole pursuant to a tolling agreement between Seminole and Shady Hills. The petitions were filed pursuant to Sections 366.04 and 403.519, Florida Statutes (F.S.), and Rules 25-22.080, 25-22.081 and 28-106.201, Florida Administrative Code (F.A.C.).

Docket Nos. 20170266-EC and 20170267-EC were consolidated for hearing purposes by Order No. PSC-2018-0018-PCO-EC, issued on January 5, 2018. On January 17, 2018, Michael Tulk and Patrick Daly filed a Motion to Intervene in both dockets. Quantum Pasco Power, L.P. (Quantum) also filed a Motion to Intervene in both dockets on January 17, 2018. On January 24, 2018, Order No. PSC-2018-0062-PCO-EC, was issued granting Michael Tulk and Patrick Daly intervention. Order No. PSC-2018-0063-PCO-EC, also issued on January 24, 2018, granted intervention to Quantum. (Michael Tulk, Patrick Daly, and Quantum Pasco Power, L.P. are collectively referred to as Intervenors). On March 12, 2018, a prehearing conference was held. The hearing was held on March 21 through 22, 2018.

The Florida Public Service Commission (Commission) has jurisdiction over the subject matter of this proceeding pursuant to Sections 366.041 and 403.519, F.S.

Discussion of Issues

Issue 1A: Is there a need for the proposed Seminole Combined Cycle Facility, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519(3), Florida Statutes?

Issue 1B: Is there a need for the proposed Shady Hills Combined Cycle Facility, taking into account the need for electric system reliability and integrity, as this criterion is used in Section 403.519(3), Florida Statutes?

Recommendation: Yes. Seminole's models and forecasts of seasonal peak demand and net energy for load through 2027 are reasonable based on methodological changes which Seminole initiated in 2014 through 2017. With the expiration of existing power purchase agreements (PPAs), staff recommends that Seminole has demonstrated a need for the Shady Hills Facility in 2021 and the Seminole Facility in 2022 to maintain its system reliability and integrity. (Thompson, McNulty, Higgins, Bryant)

Position of the Parties

Seminole Issue 1A: Yes. Seminole has demonstrated a reliability need for 901 MW of additional generating capacity by the end of 2021 and 1,265 MW by the end of 2022, as well as a need for the additional capacity to be provided by the SCCF and SHCCF because it will displace higher cost coal-fired generation.

Petitioners Issue 1B: Yes. Seminole has demonstrated a reliability need for 901 MW of additional generating capacity by the end of 2021 and 1,265 MW by the end of 2022, as well as a need for the additional capacity to be provided by the SCCF and SHCCF because it will displace higher cost coal-fired generation.

Intervenors Issue 1A: No. Seminole's need forecasts are not reliable because they have historically been biased toward significantly overstating forecast values as compared to actual values observed. Seminole's new load forecasting methodology is at best unproven. Even if Seminole's need forecasts were accurate, Seminole can more cost-effectively meet those (probably overstated) needs using PPAs through 2027, as shown by Seminole's NO BUILD RISK Portfolio, followed by lower-CPVRR additions properly evaluated in the mid-2020s.

Intervenors Issue 1B: No. Seminole's need forecasts are not reliable because they have historically been biased toward significantly overstating forecast values as compared to actual values observed. Seminole's new load forecasting methodology is at best unproven. Even if Seminole's need forecasts were accurate, Seminole can more cost-effectively meet those (probably overstated) needs using PPAs through 2027, as shown by Seminole's NO BUILD RISK Portfolio, followed by lower-CPVRR additions properly evaluated in the mid-2020s.

Parties' Arguments

Petitioners

The Petitioners maintain that Seminole's current load forecast is reasonable for purposes of this proceeding. (Petitioners BR 8-9) The Petitioners' witness Wood testified that Seminole's load forecast has undergone significant improvements beginning with Seminole's 2014 Load Forecast Study (LFS) and continuing through the study that produced the load forecast supporting the Petitioners' petitions in this proceeding, the 2017 LFS. (Petitioners BR 7-8) The Petitioners' witness Hong further testified that improvements to Seminole's load models and forecasts have been shown to be effective in maintaining a reasonable level of forecast error since 2014 through a technique of isolating forecast model error called ex-post analyses.[1] (Petitioners BR 8)

The Petitioners state that Seminole's gap analysis, used to identify deficiencies between forecasted requirements and current available capacity, shows that Seminole will need 901 MW of generation by the end of 2021 to meet Seminole's members' energy needs and its reserve margin requirements. The Petitioners assert that Seminole's future capacity need results primarily from the expiration of PPAs and that this need will grow to 1,265 MW in 2022, with the expiration of an additional PPA and expected load growth. (Petitioners BR 6) Regarding the Intervenors' argument that Peninsular Florida reserve margins are projected to be adequate to meet Seminole's need through at least 2026, the Petitioners argue that Seminole tested the marketplace through the request for proposals (RFP) process and developed a balanced portfolio including existing capacity resources located within Peninsular Florida. (Petitioners BR 9) The Petitioners further argue that Intervenors can cite no Commission precedent for the proposition that Seminole must rely on excess Peninsular Florida capacity, in lieu of new generation resources, without regard to cost-effectiveness or other relevant considerations, such as transmission impacts. (Petitioners BR 9)

Intervenors

The Intervenors maintain that Seminole has consistently and significantly overstated its projected winter and summer peak demand and its net energy for load (NEL) as demonstrated by the Intervenors' witness Sotkiewicz's forecast error calculations (units and rates) based on Seminole's 2005 through 2012 forecasts. Therefore, Seminole's current forecasts cannot be used as a basis for supporting Seminole's purported need for the combined capacity of the Seminole Facility and the Shady Hills Facility. (Intervenors BR 14) According to witness Sotkiewicz, Seminole's winter peak forecasting errors five-years out have averaged 1,381 MW (39 percent), which he notes is more than Seminole's projected "Winter Need Gap" of 1,336 MW for 2024 as testified to by the Petitioners' witness Diazgranados. (Intervenors BR 13-14)

The Intervenors maintain that, while Seminole's forecasting methodology has been updated, it is unproven in any comparison of forecast versus actual values. The Intervenors assert that Seminole's load forecasts have a demonstrated bias toward over-forecasting load requirements three to five years into the future over the last decade, and thus are a cause for extreme doubt as

[1]Witness Wood described ex-post forecast error analyses as an "after-the-event" evaluation of model error with observed (actual) explanatory variable data which removes the error associated with long-term forecasts of weather and economy, thereby allowing insight into model improvements. (TR 631-632)

to Seminole's need for the Seminole Facility and the Shady Hills Facility for system reliability and integrity. (Intervenors BR 9)

The Intervenors assert that Peninsular Florida's reserve margins are projected to be adequate to meet all reliability criteria through at least 2026, without the Seminole Facility or the Shady Hills Facility. (Intervenors BR 13) The Intervenors further assert that the additional flexibility of shorter-term PPAs through the No Build Risk: All PPA Portfolio (No Build Portfolio) will allow Seminole to better match resources with needs. (Intervenors BR 16)

Staff Analysis: The Petitioners' need assessment process demonstrated that, in order to meet Seminole's established reliability criteria, approximately 1,265 MW of additional capacity will be needed by the end of 2022. (TR 57) This capacity need results primarily from the scheduled expiration of several PPAs and expected load growth. (EXH 3)

Seminole's Load Model and Forecasting Overview

Seminole's load forecasts submitted in support of its proposals in this proceeding, including its forecasts of consumers (i.e. number of customers), winter and summer peak demand, and NEL, are aggregates of the forecasts Seminole prepares for each of its nine members. Witness Wood testified that Seminole creates econometric models to prepare forecasts for its members using model assumptions collected from the members, government agencies, universities, and third party providers. (TR 285) The annualized load forecasts for the years 2017 through 2027, which are used to support its petition in this proceeding, appear in Seminole's December 2017 Need Study. (EXH 3) In addition to the base forecasts, Seminole includes both high case and low case projections of demand based on the 10th and 90th percentile ranks of temperature distribution derived from past temperatures. (EXH 74)

Seminole's forecast of winter peak demand is of particular importance in this proceeding for evaluating the need for the proposed generating plant additions because Seminole is a winter peaking utility. (TR 283-284; TR 443) Witness Wood testified that Seminole's winter peak demand models regress independent variables with the highest peak during November through March, while the summer peak demand models regress independent variables with the highest peak during April through September. (TR 287) Seminole's member-specific winter peak demand models include variables such as: member forecasted consumer growth or population projections; heating degree days interacting with heating end-use equipment/appliance forecasts; load factor; and in most cases, Seminole's wholesale electricity price (in real terms). (EXH 64)

A key consideration in this docket is whether the additional capacity associated with the Seminole Facility and Shady Hills Facility is needed to meet Seminole's winter peak demand, and if so, when. (TR 628-629) The discussion below addresses whether Seminole's winter peak demand forecast is reasonable prior to considering the generation and purchase power aspects of Seminole's need proposal.

History and Forecast of Seminole's Winter Peak Demand

Presented in Table 1-1 below is staff's overview of Seminole's actual and projected peak demand and NEL requirements for the period 2012 through 2027.

Table 1-1
Seminole Historical and Projected Peak and Net Energy for Load Requirements

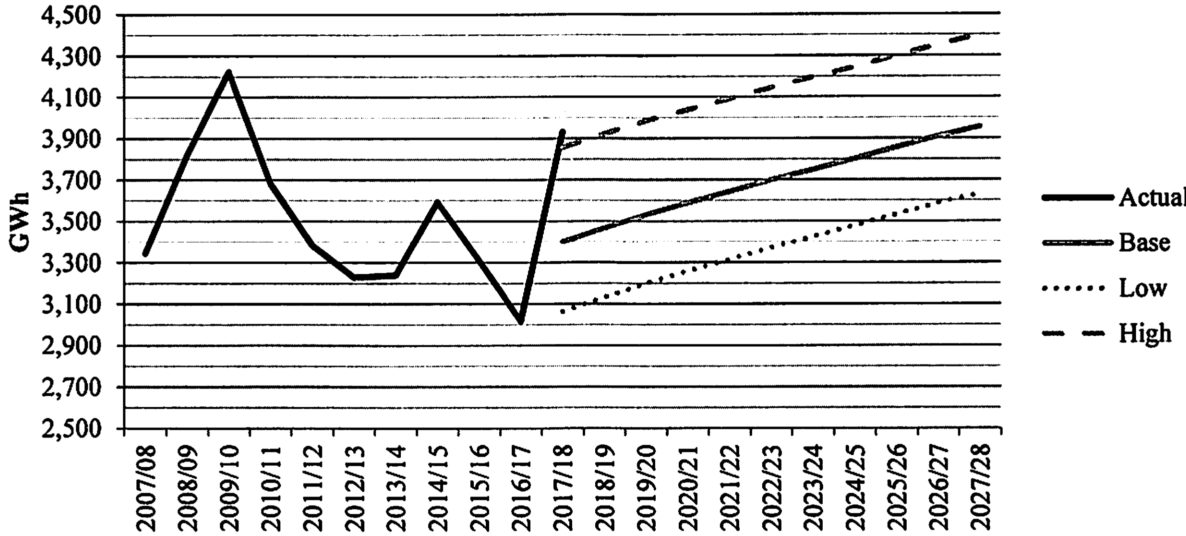
Year	Winter Peak (MW)	Summer Peak (MW)	Net Energy for Load (GWh)
2012 (actual)	3,229	2,890	13,256
2017 (actual)	3,932	3,114	14,325
2018 (projected)	3,466	3,140	14,601
2022 (projected)	3,699	3,297	15,306
2027 (projected)	3,955	3,516	16,437
Actual Growth (2012-2017)	703	224	1,069
Projected Growth (2018-2022)	233	156	705
Projected Growth (2018-2027)	490	375	1,836
CAGR, 2012-2017*	4.02%	1.50%	1.56%
CAGR, 2018-2022*	1.64%	1.22%	1.19%
CAGR, 2018-2027*	1.48%	1.26%	1.32%
*CAGR = ((Ending Value / Beginning Value) ^ (1/Number of Periods)) – 1			
Note: Growth figures may not compute due to rounding.			

Source: EXH 3; EXH 85; TR 340

The 2018 through 2022 compound annual growth rates (CAGR) of Seminole's forecasted winter peak, summer peak, and net energy for load are less than the actual CAGRs over the recent period of 2012 through 2017. Staff understands the CAGR of winter-peak requirements for the period of 2012 through 2017 to be skewed by a colder-than-projected 2017- 2018 winter season. (EXH 79) Seminole showed a forecasted 2017-2018 winter peak requirement of 3,398 MW in its December 2017 Need Study, when its actual 2017-2018 winter peak demand was 3,932 MW, for an under-forecast of 534 MW. Seminole's winter-peak growth for the 2018 through 2022 period is projected to be approximately 233 MW. (EXH 3; TR 340)

A graphical representation of Seminole's winter demand beginning in 2007, including actual data showing the 2017-2018 winter, and forecasted data through 2027, with Seminole's alternative high and low forecasts, appears below in Figure 1-1.

Figure 1-1
Winter Peak Demand



Source: EXH 3; TR 340; TR 354

Seminole's Historical Load Forecast Error

The Intervenors' witness Sotkiewicz testified that Seminole's extreme historical winter demand forecast errors, indicating an overforecasting bias, are evidence that Seminole's current load forecast cannot be used as a basis for claiming need for either the Seminole Facility or the Shady Hills Facility. (TR 572; TR 575) In his rebuttal testimony, Seminole witness Wood provided four reasons why he believes witness Sotkiewicz was incorrect in his assessment of Seminole's load forecast error. (TR 625-632) The reasons include:

1. Forecast Process Improvements - Witness Wood testified that Seminole has implemented a series of improvements to its load forecasting process and methodology from 2014 through 2017 that are relevant to this case. Such improvements included: various changes to its end use model; transitioning to forecasting total energy requirements rather than usage per customer using hourly delivery point data, transitioning to "SAS on Windows PC" software in place of "SAS on Mainframe" for modeling and forecasting; expanding its weather stations from 8 to 25 while also enhancing its weather station selection process; and, replacing saturation and efficiency variables with Itron, Inc. energy intensity variables. (TR 626; TR 656-657; EXH 64)

2. Incorrect Forecast Error Calculations - Witness Wood presented a "corrected" analysis of witness Sotkiewicz's calculation of Seminole's historic forecast errors three, four, and five-years out. Witness Wood's "corrected" analysis indicated such error rates were significantly lower than the error rates presented by witness Sotkiewicz, albeit still high (e.g., 21 percent error rate for winter peak demand forecasts five years-out, as opposed to 39 percent per witness Sotkiewicz). (TR 629-631; EXH 66)

3. Other Florida Utilities Had High Forecast Errors - Witness Wood testified that witness Sotkiewicz's approach yields a similar magnitude of historical forecast errors for Seminole, Duke Energy Florida (DEF), and Tampa Electric Company (TECO), and that many utilities during the period in question (2005 through 2013) had high forecast errors due to the effects of the Great Recession. (TR 628-629; EXH 65)

4. Reasonably Low Ex-Post Forecast Errors - Witness Wood testified Seminole has been conducting ex-post forecast error analyses of its annual load since 2015. Witness Wood testified that Seminole's 2017 ex-post forecast error analysis ranged from 2.3 to 3.5 percent for the winter demand model, and Seminole witness Hong testified that such error rates were "reasonably low." (TR 632; TR 672)

First, staff reviewed the extent of Seminole's changes to its load model and forecast process. The following is a list of the model changes Seminole adopted beginning in 2015, which were expected to improve Seminole's winter peak demand model and forecast methodologies and data accuracy:

A. Weather Data – Seminole expanded the number of weather stations from 8 to 25, increased types of weather data used, and improved its weather station selection methodology to reduce forecast error. (EXH 64)

B. Load Data – Seminole used hourly delivery point data to model and forecast total energy and demand requirements rather than continuing to rely upon forecasts of consumer meters, usage per meter, and extrapolated loss and load factors. (EXH 64)

C. Appliance Saturation and Efficiencies – By joining Itron's Energy Forecasting Group, Seminole enhanced its ability to account for trends in structural changes, end-use appliance saturation, and efficiencies, thereby taking advantage of the latest trends and indices, adapted to Seminole's Member data. (EXH 64)

D. Forecast Technology – Converting to "SAS on Windows PC" from "SAS on the Mainframe" reportedly allowed Seminole to include new data and make its modeling and forecasting process more flexible and robust. (EXH 64; TR 625-626)

These identified changes in methodology and data, incorporated over the 2014 through 2017 time period, appear to be broad-based modifications to the methodology and data used in Seminole's prior load models and forecasts. These changes appear to be improvements, offering a higher level of precision, a greater level of detail, and a more flexible and robust forecasting software platform for modeling and forecasting operations.

With regard to witness Wood's second reason for rejecting witness Sotkiewicz's allegation of overforecast bias, witness Wood's series of corrections to witness Sotkiewicz's historical load forecast error included: (a) the graduated removal of Lee County Electric Cooperative's load forecast data from Seminole's load forecasts shown in the 2005, 2006, and 2007 Ten-Year Site

Plans[2]; (b) recognition that Seminole's LFSs are prepared in the year prior to the Ten-Year Site Plan in which they appear; and (c) recognition of the biennial production of load forecast studies before 2008.[3] (TR 627-628) Staff notes that witness Sotkiewicz did not refute witness Wood's corrections in his Supplemental Testimony, nor did he amend his own testimony to include witness Wood's corrections. (TR 602-603) Staff has reviewed witness Wood's corrections to witness Sotkiewicz's analyses of Seminole's historical forecast error rates and witness Wood's corrections appear to be well-supported. (EXH 95; EXH 97)

Staff reviewed Seminole's corrected historical average winter peak demand forecast error rate five-years out, equal to positive 21 percent, with regard to the proposed in-service date of the Seminole Facility, and staff considers this error rate, while lower than the rate estimated by witness Sotkiewicz, to be high. (EXH 66) Also, in order to apply historical load forecast error as a proxy for the first year the Shady Hills Facility is proposed to come on line, in late 2022, Seminole would have had to present a six-year out historical load forecast error rate. Seminole did not provide such information in this proceeding. The effectiveness of the changes Seminole made to its load forecast process and methods from 2014 to 2017 to address high historical forecast errors is the subject of witness Wood's ex-post forecast error analysis.

Staff reviewed witness Wood's third reason to reject witness Sotkiewicz's allegation of overforecast bias, wherein witness Wood testified that other utilities with similar size and geographic characteristics also experienced high load forecast errors during the historical forecast period included in witness Sotkiewicz's testimony. (TR 628-629) Staff agrees that the historical load forecast errors for forecasts prepared through 2012 were similarly high for the two other utilities witness Wood selected for comparison purposes, DEF and TECO. Witness Wood testified that, as a point of comparison, many utilities in Florida struggled with load forecast errors beginning with the onset of the Great Recession in 2008. (TR 627) At hearing, witness Wood testified, "I would say the majority of [Seminole's] error was caused by the great recession and the onset of federally implemented energy efficiency codes and standards," but he admitted that the absence of the load modeling and forecasting enhancements that Seminole adopted later contributed to the high error rates. (TR 660-661) It may be reasonable to expect that the Great Recession initially had a negative impact on forecast accuracy; however, staff notes that the record does not contain metrics identifying the specific causes of Seminole's load forecast errors.

Witness Wood's analyses of Seminole's, DEF's, and TECO's comparative load forecast errors do not include a comparison of 2013 load forecast errors.[4] (EXH 65) Staff notes that Seminole reported continued high winter peak demand forecast error rates as late as the 2013 LFS (e.g.,

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[2] Reflects removal of Lee County Electric Cooperative data for forecasts appearing in the 2005-2007 Ten-Year Site Plans for forecast periods beginning in 2008, when reductions in load to that utility became known and recognized. (TR 627-628)

[3] Seminole's 2005 Ten-Year Site Plan reflects the 2003 LFS; Seminole's 2006 and 2007 Ten-Year Site Plans both reflect the 2005 LFS. Thus, new forecasts were not produced in the 2005 and the 2007 Ten-Year Site Plans. (TR 628)

[4] In his analysis, witness Wood included data through the 2013 Ten-Year Site Plans, but the 2013 Ten-Year Site Plan is based on forecasts prepared in 2012, not 2013, consistent with his testimony that forecasts are prepared the year prior to the Ten-Year Site Plan in which they appear. (EXH 65; TR 628)

16.9 percent error rate for its forecasts prepared three-years out, which was the 2015-2016 winter season), despite a large increase in heating degree days compared to the prior winter season, 2014-2015. (EXH 66; EXH 79) This is an indication that the issue of high historical load forecast errors for Seminole may not be fully attributed to the impacts of the Great Recession, which officially ended in June 2009. (TR 648) Based on Seminole's high historical average forecast error rates (overforecasts) contained in Seminole's load forecast studies through 2013, it appears that significant improvements in Seminole's load forecast process and methods were necessary to improve the accuracy of Seminole's load forecasts. (EXH 66) As discussed above, Seminole launched a series of changes to its load model and forecast process in its 2014, 2015, 2016, and 2017 LFSs designed to improve load forecast accuracy. (EXH 64; TR 656) In addition to the changes to Seminole's load forecast process and methods, staff reviewed whether the evidence in this case suggests that such changes have resulted in reasonably accurate forecasts.

In this regard, Witness Wood's fourth reason to reject witness Sotkiewicz's allegations of overforecast bias relates to Seminole's initiation of its ex-post forecast error analysis for demand and energy beginning in 2015. Seminole's analysis is an error-estimating procedure that is based on replacing the original estimated weather and economic data with actual weather and economic data in the forecast model to generate an "after the fact", or ex-post, forecast devoid of weather and economy errors. (TR 631-632) The difference in the actual demand and the ex-post demand forecast is the remaining error rate which is meant to be an indicator of the magnitude of the error in Seminole's model. (TR 631-632) The ex-post forecast error for Seminole's 2017 winter peak demand based on the 2016 LFS (two-years out) was 3.5 percent. Seminole's ex-post forecast for Seminole's 2016 winter peak forecast error (one-year out) was 2.3 percent. (TR 672) Witness Hong testified that this level of error was reasonably low. (TR 672) This lends some credibility to the notion that the modeling changes, which Seminole made beginning in 2014, have resulted in a reasonable level of error rates one and two-years out. However, staff notes that the error rates of most interest in this proceeding are for the forecasts that are five and six-years out.

In addition to reviewing witness Wood's reasons for rejecting witness Sotkiewicz's allegations of overforecast bias, staff conducted two other areas of review using record evidence to examine whether Seminole had adequately addressed the high historical forecast errors in its more recent load forecasts. First, staff reviewed Seminole's recent ex-ante forecast error, which is forecast error without adjustments for weather and economic data. Seminole's 2014 through 2017 winter demand forecasts, conducted during the period of modeling/forecasting method changes, may or may not produce error rates that would follow the pattern of the forecasts that came before (overforecasts). In reviewing such error rates, consideration may be given to significant impacts due to weather or other volatile and uncontrollable factors which may have been present. The related ex-ante analysis appears below in Table 1-2.

Table 1-2
Seminole Winter Peak Demand Ex-ante Forecast Error Rates, 2011-15 Load Forecast Studies

Actual Winter Peak Demand Period	Actual Demand	Load Forecast Study Year	"3-Years Out" MW Error	Percent Error	Load Forecast Study Year	"4-Years Out" MW Error	Percent Error
2014-15	3,593	2012	3,949	9.91%	2011	4,054	12.83%
2015-16	3,307	2013	3,866	16.90%	2012	4,022	21.62%
2016-17	3,018	2014	3,516	**16.50%**	2013	3,978	31.81%
2017-18	3,932	2015	3,539	**-9.99%**	2014	3,588	**-8.75%**
Note: Bolded entries denote results beginning with Seminole's 2014 LFS.							

Sources: EXH 57; EXH 65; EXH 66; TR 340

Table 1-2 shows that the three available data points for three and four-year out winter peak demand error since the initiation of load forecast process changes in 2014 were the three-year out forecasts of 2016-2017 and 2017-2018 winter seasons, and the four-year out forecast for the 2017-2018 winter season. Two out of the three error rates noted above are negative, indicating underforecasts had occurred, which is not unexpected since winter peak temperatures were lower than normal for the 2017-2018 winter season. (TR 354-355) The three-year error rate for 2016-2017 was strongly positive at 16.50 percent, but that occurred in a year when the actual temperatures in January and February of 2017 were very mild (higher than normal). (EXH 79) From the available data, these forecast data points appear to indicate Seminole's recent winter peak demand forecasts are less prone to being overforecasts at three and four-years out than they were historically. (EXH 66)

Staff's second additional area of review was to determine whether Seminole's 2014 through 2017 load forecasts show significant decreases in demand and energy compared to the 2013 load forecasts for the relevant years in this proceeding (i.e., 2021 through 2023). If Seminole's load modeling/forecasting changes were effective in making Seminole's forecast more accurate, the forecast amounts would be expected to decrease significantly, based on Seminole's history of high overforecasts. The related review is shown below in Table 1-3 for Seminole's winter peak demand.

Table 1-3
Year over Year Percent Change in Winter Peak Demand Forecasts

Load Forecast Study	Winter Season			
	2021-22		2022-23	
	MWs	Percent Change	MWs	Percent Change
2013	4,540	-	4,651	-
2014	3,831	-15.6%	3,887	-16.4%
2015	3,744	-2.3%	3,787	-2.6%
2016	3,750	0.2%	3,803	0.4%
2017	3,643	-2.9%	3,699	-2.7%
2017–2013	-897	-19.8%	-952	-20.5%

Source: EXH 112; TR 628

Table 1-3 above indicates that significant reductions occurred in Seminole's 2014 winter peak demand forecast relative to Seminole's 2013 winter peak demand forecast, and additional, albeit smaller, reductions occurred in the 2015 and 2017 winter peak forecasts. Seminole's 2017 LFS's overall reduction in its winter peak demand forecast for the projected in-service year of the Seminole Facility is 897 MW, or 19.8 percent, relative to Seminole's 2013 LFS's forecast.

Staff has reviewed Seminole's load models and forecast methods, assumptions, data, data sources, statistics, and error rates and recommends that Seminole's load models and forecasts appear reasonable to staff. Moreover, the Intervenors have not provided any alternative load forecasts in this proceeding.

Summary of Load Forecasting

Witness Sotkiewicz testified that he strongly doubts the accuracy of Seminole's load forecasts because Seminole has historically experienced high load forecast error rates, and its new forecasting methodology and new inputs remain unproven. (TR 602-603) Staff recommends that witness Sotkiewicz is not persuasive based on Seminole's broad-based load modeling and forecasting changes, reasonable levels of winter peak demand ex-ante and ex-post forecast errors in recent years, as well as significantly reduced winter peak demand forecasts beginning in 2014 and extending through 2017. Additionally, it would be difficult, if not impossible, to address matters such as generation expansion without the ability to evaluate the suitability of updated utility load forecasts for regulatory purposes, including those cases wherein a utility's forecasts are deemed to have high historical forecast error rates. The above quantitative and qualitative analyses, taken together, appear to indicate that Seminole's changes to its load modeling/forecasting methods and processes have improved its forecasting accuracy. In sum, staff recommends that Seminole's models and forecasts of customers, winter and summer peak demand, and net energy for load are reasonable for purposes of considering the need for the Seminole Facility and the Shady Hills Facility.

Reserve Margin

According to the Petitioners' witness Diazgranados, Seminole has two principal reliability criteria: (1) a 15 percent reserve margin; and, (2) a loss of load probability of one day in ten-years. (TR 442) The record indicates that Seminole's forecasted load and winter peak reserve margin are the primary drivers for its need. (TR 443) As shown in Table 1-4 below, beginning in the 2021/22 timeframe, Seminole's winter reserve margin is expected to be below its required 15 percent reserve margin criterion if no capacity is added. (EXH 74) The expiration of multiple PPAs will cause a drop of 947 MW in available capacity, and load growth is projected to increase Seminole's winter peak demand by 229 MW by 2023, as shown below. (EXH 74) The Petitioners assert that this would possibly leave Seminole's members and member-consumers at a high risk of service interruptions. (TR 451)

Table 1-4
Winter Reserve Margin with No Additional Capacity

Year	Capacity Available (MW)	System Firm Peak Demand (MW)	Reserve Margin
2018/19	4,496	3,470	30%
2019/20	4,746	3,537	34%
2020/21	4,595	3,595	28%
2021/22	3,849	3,643	6%
2022/23	3,549	3,699	-4%

Source: EXH 74

Seminole proposes to meet its need with what it has denoted as the Clean Power Plan/Combined Cycle (CPP/CC) Portfolio. (TR 443-444; TR 447-448) As further discussed in Issues 5A and 5B, this portfolio includes adding the Shady Hills Facility in 2021, the Seminole Facility in 2022, retiring one of the two SGS coal units in 2022, and multiple PPAs. (EXH 74) As shown in Table 1-5 below, Seminole's projected winter reserve margin with the CPP/CC Portfolio is expected to satisfy Seminole's reserve margin criterion. (EXH 74)

Table 1-5
CPP/CC Portfolio Winter Reserve Margin

Year	Capacity Available (MW)	System Firm Peak Demand (MW)	Reserve Margin
2018/19	4,496	3,470	30%
2019/20	4,746	3,537	34%
2020/21	4,595*	3,595	28%
2021/22	4,200	3,643	15%
2022/23	4,264	3,699	15%
*Note: There appeared to be a typo in the response, therefore, this value was taken from the No Planned Capacity Excel sheet.			

Source: EXH 74

Witness Sotkiewicz argued that Seminole's need forecasts are not reliable because Seminole has been biased in overstating forecast values, and further argues that Seminole's updated forecasting methodology is unproven. (TR 602-603) As previously discussed, staff recommends that Seminole's updated forecasting methodology is sufficient. However, as indicated by witness Diazgranados, the primary driver of Seminole's need is the loss of PPAs. (TR 443) The PPAs expiring result in a loss of available capacity to Seminole that will need to be replaced to provide reliable service to Seminole's members.

The Intervenors argue that Peninsular Florida reserve margins are projected to be adequate to meet all reliability criteria through at least 2026 without constructing the Seminole Facility or the Shady Hills Facility. However, the Petitioners argue that the Intervenors can cite no Commission precedent for the proposition that Seminole must rely on excess Peninsular Florida capacity, in lieu of new generation resources, without regard to cost-effectiveness or other relevant considerations, such as transmission impacts. Also, the Petitioners' witness Ward noted that approximately 80 percent of Seminole's member load is located in the DEF balancing area. (TR 138) He further asserted that having excessive generation resources outside of that balancing area would require wheeling through multiple areas. (TR 138) Because wheeling would add additional transmission costs and risks to Seminole's members, and reduce Seminole's electric system reliability and integrity, staff disagrees with the Intervenors' argument and recommends that the Petitioners' argument is persuasive.

The Intervenors also argue that Seminole can meet its needs more cost-effectively with PPAs through 2027. (TR 574-575) Cost-effectiveness will be addressed in Issues 5A and 5B. Based on the foregoing, staff recommends that Seminole does have a reliability need and the record demonstrates that the portfolio including the Seminole Facility and the Shady Hills facility will sufficiently address this need.

Conclusion

Seminole's models and forecasts of seasonal peak demand and net energy for load through 2027 are reasonable based on methodological changes which Seminole initiated in 2014 through 2017. With the expiration of existing PPAs, staff recommends that Seminole has demonstrated a need for the Shady Hills Facility in 2021 and the Seminole Facility in 2022 to maintain its system reliability and integrity.

Issue 2A: Are there any renewable energy sources and technologies or conservation measures taken by or reasonably available to Seminole Electric Cooperative, Inc., which might mitigate the need for the proposed Seminole Combined Cycle Facility?

Issue 2B: Are there any renewable energy sources and technologies or conservation measures taken by or reasonably available to Seminole and Shady Hills Energy Center, LLC, which might mitigate the need for the proposed Shady Hills Combined Cycle Facility?

Recommendation: No. Staff recommends that renewable energy resources and conservation measures are incorporated into Seminole's system planning to the extent reasonably available, including the recent addition of 40 MW of summer solar photovoltaic (PV) capacity. As a wholesale provider of electricity, Seminole provides appropriate price signals to encourage conservation. (Wright)

Position of the Parties

Seminole Issue 2A: No. As a winter-peaking utility, Seminole experiences its highest demand when solar energy is not a viable capacity source. As such, additional renewable energy is not reasonably available to mitigate Seminole's need. Seminole's wholesale rate structure provides price signals that encourage Members to implement conservation measures aimed at reducing Seminole's system peak. Despite the conservation savings achieved by its Members, Seminole needs additional capacity and conservation measures are not reasonably available to mitigate that need.

Petitioners Issue 2B: No. As a winter-peaking utility, Seminole experiences its highest demand when solar energy is not a viable capacity source. As such, additional renewable energy is not reasonably available to mitigate Seminole's need. Seminole's wholesale rate structure provides price signals that encourage Members to implement conservation measures aimed at reducing Seminole's system peak. Despite the conservation savings achieved by its Members, Seminole needs additional capacity and conservation measures are not reasonably available to mitigate that need.

Intervenors Issue 2A: Yes. Seminole received numerous proposals totaling more than 3,000 MW of solar generating capacity; thus, there are renewable energy options that are at least "reasonably available" to Seminole to meet its needs. Further, solar costs and solar-with-storage costs are declining, but Seminole failed to adequately examine these important options. Seminole and its Member Coops should also be able to achieve substantial additional peak reductions, comparable to other FEECA utilities, through conservation.

Intervenors Issue 2B: Yes. Seminole received numerous proposals totaling more than 3,000 MW of solar generating capacity; thus, there are renewable energy options that are at least "reasonably available" to Seminole to meet its needs. Further, solar costs and solar-with-storage costs are declining, but Seminole failed to adequately examine these important options. Seminole and its Member Coops should also be able to achieve substantial additional peak reductions, comparable to other FEECA utilities, through conservation.

Parties' Arguments

Petitioners

Petitioners assert that Seminole's generating mix already includes reasonably available renewable resources. (Petitioners BR 11) Petitioners also argue that the results of Seminole's RFP process show that additional renewable energy resources would not be cost-effective compared to the Seminole Facility or Shady Hills Facility. (Petitioners BR 11) Moreover, Petitioners maintain that Seminole is a winter-peaking utility and solar energy is not a viable capacity source to offset its peak demand. Nevertheless, Petitioners note that Seminole has included 40 MW (summer) of solar in the selected resource plan. (Petitioners BR 11)

Petitioners assert that, as a wholesale supplier of electric energy to its members, Seminole is not directly responsible for demand-side management (DSM) programs but that Seminole's wholesale rate structure provides members price signals that encourage conservation. (Petitioners BR 12) Petitioners also argue that Seminole assists its members in evaluating and implementing DSM measures. (Petitioners BR 12) Petitioners state that Seminole recently engaged Advanced Energy and Tierra Resource Consultants (AE/Tierra) to identify potential new conservation programs and to evaluate their cost-effectiveness. (Petitioners BR 13) Petitioners note that none of the additional measures evaluated by AE/Tierra satisfied the Rate Impact Measure test. (Petitioners BR 14)

Intervenors

Intervenors argue that there is more than 3,000 MW of solar generating capacity available to meet Seminole's needs. (Intervenors BR 30) Further, Intervenors attest that solar costs and solar-with-storage costs are declining, and that Seminole failed to adequately examine these important options. (Intervenors BR 35) Intervenors also assert that there is likely significant additional conservation potential to help mitigate the need for either the Seminole Facility or Shady Hills Facility. (Intervenors BR 31) Intervenors note that, through 2016, utilities subject to Florida's Energy Efficiency Conservation Act (FEECA) have achieved 17 percent of the Florida Reliability Coordinating Council region's projected 2017 firm winter peak demand in winter peak demand reductions. Intervenors maintain that Seminole, by comparison, has achieved 5.8 percent of its firm winter peak as winter peak demand reductions. (Intervenors BR 31) Therefore, Intervenors contend that if such winter peak demand reductions have been achieved by Florida's FEECA utilities, these reductions are at least reasonably attainable to Seminole and its members. (Intervenors BR 31)

Staff Analysis:

Renewable Energy Sources and Technologies

Witness Ward argues that Seminole's generation portfolio currently incorporates various renewable generation resources. (TR 56) In terms of winter capacity, biomass facilities account for 13 MW, landfill gas-to-energy facilities for 16.8 MW, and waste-to-energy facilities for 58 MW, in addition to 2.2 MW of summer solar PV capacity from the Cooperative Solar facility. (TR 56; EXH 5; EXH 3) A provision in Seminole's Member Wholesale Power Contract gives

Seminole's members the flexibility to install distributed renewable generation with capacity amounts up to five percent of the member's three-year average peak demand. (TR 54; EXH 74)

Seminole recently added renewable resources to its system, namely 40 MW of summer capacity from the Tillman Solar Center, a solar PV facility. (TR 59; EXH 6) When evaluating responses to its March 2016 RFP, witness Ward states that Seminole had concerns with the viability of solar capacity sources to offset its winter peak demands. (TR 59; EXH 27) Petitioners attest that Coronal, the bidder associated with the Tillman Solar Center, provided the lowest-priced offer and that Coronal would honor this price for a project within the 40 MW to 75 MW range. (EXH 79) Seminole opted for the 40 MW size to evaluate the effects of a mid-size solar facility on its system. (EXH 79)

Petitioners' witness Peters argues that, while the renewable resource responses to Seminole's RFP largely consisted of solar facility proposals, a number of non-solar proposals were also received. These covered a wide-range of renewable technologies including landfill gas, waste-to-energy, wind, and battery storage. (TR 404; EXH 27) Witness Ward notes that Seminole ultimately rejected all of the non-solar proposals because they were not as economical as the traditional generating proposals received. (TR 71; EXH 80) Sedway Consulting, Seminole's contracted independent evaluator, performed a parallel RFP analysis and the results corroborated Seminole's decisions. (EXH 27) Further discussion on the evaluation of the RFP process can be found in staff's recommendation for Issues 5A and 5B.

Under cross-examination by Intervenors, Petitioners' witness Taylor testified that Seminole received RFP responses totaling approximately 3,000 MW of solar generating capacity. (TR 530) Intervenors argue that these proposals demonstrate that there are "significant amounts" of renewables reasonably available to Seminole. Witness Taylor also testified that the cost of solar and solar-with-storage facilities are declining. (TR 531-532) Intervenors' witness Sotkiewicz stated that should Seminole use an "All-PPA Portfolio" for the next 7-10 years, this would give Seminole an opportunity to observe whether additional improvements in renewable technologies, such as solar-with-storage, come about. (TR 594) As discussed above, Seminole already incorporates renewable energy resources into its system as reasonably available and, through its RFP process, sought input from the wholesale power markets in identifying viable commercial alternatives to serve the energy demands of its members' systems. Therefore, solar and solar-with-storage providers were given an opportunity to compete on equal terms with more traditional generation facilities. Staff does not recommend that witness Sotkiewicz's argument is persuasive because Seminole retains the opportunity to observe advances in renewable technology regardless of what generation resources are incorporated into its system. Based on the forgoing, staff recommends that renewable energy resources are incorporated into Seminole's system planning to the extent reasonably available.

Conservation Measures

Witness Ward states that Seminole is a not-for-profit rural electric cooperative organized under Chapter 425, F.S. (TR 53) Staff notes that Seminole is not subject to FEECA's conservation requirements.[5] Nevertheless, witness Wood argues that Seminole has implemented a number of

[5]See Sections 366.80-366.85 and 403.519, F.S.

programs within its system that promote the use of DSM or conservation to its members. (TR 292-294; EXH 3)

Seminole's wholesale rate structure, for example, includes price signals meant to reflect Seminole's cost of supplying power in aggregate. (TR 292) These signals incentivize energy conservation during different times and are as follows: (1) a production demand charge during certain months of the year, designed to encourage member conservation during heavy-demand seasons; (2) monthly member demand charges calculated relative to Seminole's peak in that month; discouraging coincident peaking with Seminole; and, (3) Time-Of-Use fuel rates, on-peak/off-peak energy charges meant to encourage members to minimize their systems' energy use during certain times of the day. (EXH 86) Seminole supplements its wholesale rate structure by administering a coordinated load management demand reduction strategy that provides real-time notification to its members signaling when Seminole's monthly peak is expected to occur. (TR 292) Seminole, with its members, also participates in an Energy Efficiency Working Group which was formed in 2008 to coordinate and promote energy conservation and DSM programs, meeting at least two times a year. (TR 293) This group facilitates Seminole's sharing of program implementation training, technical assistance, and consumer educational material with its members. (TR 293; EXH 78) Also, as part of the Energy Efficiency Working Group, Seminole conducts cost-effectiveness studies on proposed DSM and conservation measures, provides this information to its members, and, based on member requests, assists in program implementation. (EXH 78; EXH 74) Witness Wood argues that Seminole engaged AE/Tierra to evaluate potentially available DSM and conservation measures to mitigate Seminole's capacity needs, but that none of the additional programs evaluated by AE/Tierra satisfied the Rate Impact Measure test. (TR 296; EXH 17)

Intervenors assert that there are likely conservation measures, at least reasonably available to Seminole, to help mitigate the need for either the Seminole Facility or Shady Hills Facility, and support this position by comparing Seminole's winter peak demand reductions to Florida's utilities that are subject to FEECA. (EXH 108; EXH 109; Seminole's 2017 Ten-Year Site Plan) Witness Sotkiewicz did not provide testimony regarding the reasonable availability of any conservation measures to Seminole. As discussed above, Seminole is a wholesale provider of electricity and provides appropriate pricing signals to its members. These signals facilitate incorporation of DSM and conservation measures into Seminole's members' systems. FEECA utilities, on the other hand, interface directly with their retail customers. Staff believes that the situational differences between Seminole and FEECA utilities may contribute to the disparity in conservation. As such, staff recommends that this disparity is not, in and of itself, indicative that there are additional conservation measures available to Seminole.

Based on the forgoing, staff recommends that Seminole currently incorporates a number of conservation measures into its system, and that there are no additional conservation measures reasonably available to Seminole which might mitigate the need for the proposed Seminole Facility or Shady Hills Facility.

Conclusion

Staff recommends that there are no renewable energy sources and technologies or conservation measures reasonably available to Seminole or Shady Hills which might mitigate the need for the proposed Seminole Facility or Shady Hills Facility. Staff recommends that renewable energy resources and conservation measures are incorporated into Seminole's system planning to the extent reasonably available, including the recent addition of 40 MW of summer solar PV capacity. As a wholesale provider of electricity, Seminole provides appropriate price signals to encourage conservation.

Issue 3A: Is there a need for the proposed Seminole Combined Cycle Facility, taking into account the need for adequate electricity at a reasonable cost, as this criterion is used in Section 403.519(3), Florida Statutes?

Issue 3B: Is there a need for the proposed Shady Hills Combined Cycle Facility, taking into account the need for adequate electricity at a reasonable cost, as this criterion is used in Section 403.519(3), Florida Statutes?

Recommendation: Yes. Staff recommends that Seminole's financial, fuel, and environmental cost estimates are reasonable. (Thompson, Barrett, Wu)

Position of the Parties

Seminole Issue 3A: Yes. SCCF is a highly efficient combined cycle unit, which yields lower production costs than other options. Locating SCCF at SGS provides substantial cost benefits by enabling SCCF to share existing infrastructure and transmission capacity. The results of Seminole's RFP and resource planning processes show that SCCF, together with removing a coal unit from service and SHCCF, is the most cost-effective alternative to meet Seminole's needs, resulting in $363 million of projected NPV savings.

Petitioners Issue 3B: Yes. SHCCF is a highly efficient combined cycle unit, which yields lower production costs than other options. The location of SHCCF provides substantial cost benefits by enabling SHCCF to share existing infrastructure and operational staffing. The results of Seminole's RFP and resource planning processes show that SHCCF, together with SCCF and removing a coal unit from service, is the most cost-effective alternative to meet Seminole's needs, resulting in $363 million of projected NPV savings.

Intervenors Issue 3A: No. The SCCF is not the most cost-effective alternative available to meet the needs of the ultimate retail customers who would be required to pay more than $8.2 BILLION for the SCCF's construction costs, fuel, and other costs, much of which are fixed. More cost-effective alternatives are available, and accordingly, the SCCF is not needed to meet the need for adequate electricity at a reasonable cost.

Intervenors Issue 3B: No. The SHCCF is not the most cost-effective alternative available to Seminole to the needs of the ultimate retail customers who would be required to pay more nearly $4.8 BILLION for power from the SHCCF pursuant to the 30-year Tolling Agreement. More cost-effective alternatives are available, and accordingly, the SHCCF is not needed to meet the need for adequate electricity at a reasonable cost.

Parties' Arguments

Petitioners

The Petitioners state that the Seminole Facility will include a new, state-of-the-art natural gas-fired 2x1 combined cycle facility and onsite associated facilities, adjacent to the existing SGS coal units that will utilize existing infrastructure. (Petitioners BR 16) The Petitioners assert that their project cost estimate for the Seminole Facility is based in large part on an executed fixed-price contract for power island equipment and a near-final fixed-price contract for engineering, procurement, and construction services. (Petitioners BR 17) Seminole further asserts that the power island equipment and engineering, procurement, and construction contracts were competitively bid and will comprise approximately 80 percent of the Seminole Facility's total installed cost. (Petitioners BR 17) The Petitioners argue that, based on the evidentiary record, there is no valid reason to question the reasonableness of their cost estimate for the Seminole Facility, and that the selected resource plan, including the Seminole Facility, resulted in net present value (NPV) savings of approximately $363 million as compared to the next ranked alternative portfolio over the study period. (Petitioners BR 18)

The Petitioners state that the Shady Hills Facility will include a new, state-of-the-art natural gas-fired 1x1 combined cycle generating unit and onsite associated facilities, that will be designed, constructed, owned, and operated by Shady Hills on a portion of the existing Shady Hills power plant site in Shady Hills, Florida. (Petitioners BR 18-19) The Petitioners argue that locating the Shady Hills Facility at the Shady Hills site enables the Shady Hills Facility to take advantage of nearby access to existing utility infrastructure. The Petitioners assert that the Shady Hills Facility will sell its electric capacity, energy, and ancillary services to Seminole pursuant to a 30-year tolling agreement beginning on December 1, 2021. (Petitioners BR 19) The Petitioners argue that the record demonstrates that the Shady Hills Facility will help satisfy the need for adequate electricity at a reasonable cost. (Petitioners BR 20)

Intervenors

The Intervenor's assert that the Seminole Facility and the Shady Hills Facility are not needed for adequate electricity because the CPP/CC Portfolio is not the most cost-effective alternative. (Intervenors BR 17) The Intervenors also argue that the proposed Seminole Facility and the proposed Shady Hills Facility would represent uneconomic duplication of generating facilities as a result. (Intervenors BR 20) The Intervenors argue that Seminole's discount rate exceeds its projected inflation rates; therefore, delay in committing to the Seminole Facility and the Shady Hills Facility will benefit retail customers by reducing cumulative present value revenue requirements (CPVRR). (Intervenors BR 20) The Intervenors further argue that there is a risk that Seminole's escalation or inflation assumptions are wrong, and that this risk should discourage moving forward with the Seminole Facility and the Shady Hills Facility. (Intervenors BR 27) The Intervenors assert that, even if escalation in capacity costs were exactly equal to Seminole's discount rate, customers would still see $69 million in savings over the 2018 through 2027 period with the No Build Portfolio. (Intervenors BR 29)

Staff Analysis: As discussed in Issues 1A and 1B, Seminole's capacity need results primarily from the scheduled expiration of PPAs. (EXH 3) The cost-effectiveness of the proposed projects is discussed in Issues 5A and 5B. Below is a discussion of the various economic assumptions made by Seminole associated with the construction of the Seminole Facility and the Shady Hills Facility, and staff's analysis regarding the reasonableness of these assumptions.

Proposed Plant Descriptions

The Seminole Facility

The Petitioners' witness Kezell described the proposed Seminole Facility. (TR 163-167) It will be a 2x1 combined cycle facility that will utilize two natural gas fired combustion turbine generators (CTGs) each coupled with an associated heat recovery steam generator (HRSG) that will produce steam to drive a single steam turbine generator (STG). (TR 164) The HRSGs will be provided with duct burners to provide supplemental firing for additional steam production during peak demand periods. (TR 164) Witness Kezell testified that Seminole retained Black & Veatch to help evaluate numerous power generation technologies, and that combined cycle technology was selected because the high fuel efficiency and flexible dispatch capability offered by these systems will allow the Seminole Facility to match varying system load at a low cost and with limited environmental impact. (TR 165) The Seminole Facility will have an output of 1,122 MW (winter capacity). (TR 444)

Witness Kezell stated that Seminole regularly develops generic power plant models with estimated thermodynamic and economic characteristics that are used in its generation planning process. (TR 165) Witness Kezell further stated that Seminole developed its 2x1 CC Midulla Generating Station in 2002, and has operated this facility since. (TR 165) Witness Kezell testified that the Seminole Facility will have significant flexibility in terms of its operational characteristics; specifically, the gas turbines will have an extended "turndown" capability allowing them to meet their required emission levels while firing the turbines down to as low as 25 percent of their full-fire levels. (TR 166) He asserted that this capability will allow the Seminole Facility to remain operational during low load periods, typically experienced at night, and avoid thermal stress, wear, and high emission concentrations typically associated with a shut-down/start-up cycle. (TR 166-167) Also, the Seminole Facility will be capable of running in 1x1 mode with only one of the CTGs in operation. The Seminole Facility will be capable of continuing to generate by bypassing the STG with steam generated in the HRSGs, and sending it directly to the condenser if the steam turbine trips. (TR 167) Duct firing will provide approximately 53 MW of peaking capacity, and the heat rate of the facility with and without duct firing will be approximately 6,218 and 6,349 British thermal units/kilowatt-hour higher heat value, respectively. (TR 167)

The Petitioners maintain that the Seminole Facility is expected to begin commercial operation in December 2022. (TR 56) The Seminole Facility will be located on the south side of Seminole's existing SGS site. (TR 171) The site will require a new natural gas lateral to be developed and installed, but witness Kezell testified that the total installed costs were minimized with the selection of this site. (TR 171) Witness Kezell asserted that, by building the Seminole Facility at the SGS site, Seminole will be able to take advantage of existing transmission and water resource infrastructure. (TR 171) Because locating the Seminole Facility at Seminole's existing SGS site will allow Seminole to avoid the cost of developing a new site and the cost of facilities already at the SGS site, staff believes that the Seminole Facility provides an economic advantage.

The estimated capital cost of the Seminole Facility is approximately $727 million. (TR 172) Witness Sotkiewicz argued that Seminole's cost estimate for the Seminole Facility is not reliable because Florida Power & Light Company's (FPL) estimate for essentially the same unit, the Dania Beach Clean Energy Center, is approximately 13 percent to 15.2 percent more expensive than the Seminole Facility. (TR 585-586) Witness Kezell rebutted this argument by asserting that witness Sotkiewicz failed to recognize that costs for individual combined cycle projects vary due to a number of company-specific, design-specific, and site-specific factors. (TR 692) Witness Sotkiewicz admitted that he had not had the opportunity to thoroughly evaluate Seminole's estimates; whereas, witness Kezell thoroughly discussed how the cost estimate was derived, and explained why the cost of the Seminole Facility was different than the cost of the Dania Beach Clean Energy Center. (TR 586; TR 694-703) For example, witness Kezell explained that differentiations between factors such as allowance for funds used during construction, dual fuel design, differences in gas turbines, construction schedule, per diem costs, demolition of existing infrastructure, site differences, construction parking, environmental mitigation, and cooling water infrastructure could all account for disparities between Seminole's and FPL's cost estimate. (TR 695-700) Witness Kezell further asserted that the estimate for the Seminole Facility is accurate because it is based on a fixed price contract for power island equipment and an anticipated fixed price contract for engineering, procurement and construction services. (TR 692) Witness Ward also stated that Seminole received a competitive market rate from the original equipment manufacturers and engineering, procurement, and construction companies to build the Seminole Facility in the 2022 timeframe. (TR 128) Staff recommends that the Petitioners' explanation of the capital cost estimate for the Seminole Facility is persuasive.

The Shady Hills Facility

The Petitioners' witness Mathur provided a description of the proposed Shady Hills Facility. (TR 22-25) The Shady Hills Facility will be a 1x1 combined cycle facility that will utilize one natural gas fired CTG, one HRSG, and one STG. (TR 23) The Shady Hills Facility will have an output of 573 MW (winter capacity) and have 30 to 35 MWs of duct firing capability for peaking capacity. (TR 23) The facility will tie to a new DEF substation that will connect to the DEF 230 kilovolt high voltage transmission grid in Pasco County, Florida. (TR 24)

Witness Mathur stated that the Shady Hills Facility will be located on Shady Hills' existing site in Shady Hills, Florida, allowing it to take advantage of existing transmission and water resource infrastructure. (TR 25) This facility is expected to begin commercial operation in December 2021. (TR 25) Witness Mathur stated that the Shady Hills Facility will be supported by a 30-year tolling agreement with Seminole, allowing Seminole to have the right to schedule the dispatch of the plant, provide fuel for such scheduled operation, and receive all of the power produced. (TR 22) He further stated that Seminole will make fixed payments related to the demonstrated capacity of the Shady Hills Facility, and make variable payments when the plant is dispatched per Seminole's schedules. (TR 22) Witness Mathur testified that the terms of the olling agreement provide Seminole with security of power supply at a competitive price for 30 years. (TR 22) Witness Mathur further testified that General Electric Energy Financial Services has a long history of developing and investing in combined cycle power plants, and is confident in its ability to meet the projected milestones and specifications of the Shady Hills Facility. (TR 20) Similar to the Seminole Facility, staff recommends that the Shady Hills Facility has an economic advantage by being located at the existing Shady Hills site because the cost of developing a new site will be avoided and existing infrastructure can be used.

Financial Assumptions

The instant dockets are the result of a multi-stage resource planning process that looked at numerous options to address Seminole's forecasted need for additional capacity. Seminole used data from Moody's Economic and Consumer Credit Analytics (Moody's Analytics), the Energy Information Administration (EIA), and the University of Florida's Bureau of Economic and Business Research for its forecasting and financial modeling. (TR 286; TR 288; TR 290; TR 345; TR 351-352; TR 635; TR 471; EXH 92) For its CPVRR calculations, Seminole used a discount rate of 6.0 percent, which represents its cost of capital, and used data from Moody's Analytics for escalation.[6] (TR 471; TR 712) The Intervenors' witness Sotkiewicz did not present alternative rates. Because Seminole used financial assumptions that were derived from varied and trusted sources for its CPVRR analysis, staff believes the financial assumptions are reasonable.

Fuel Costs

Fuel cost is one of the primary drivers for Seminole's economic analysis among generation alternatives in this proceeding. (EXH 3) Seminole's fuel price forecasts are derived from a combination of published market indices, independent price forecasts, and necessary escalators. (EXH 3) The New York Mercantile Exchange (NYMEX) futures forward market prices were used for projecting Henry Hub natural gas prices. (EXH 3) The EIA's Annual Energy Outlook was referenced for the rate of escalation embedded in deriving the price forecast beyond the availability of foreword NYMEX prices. (TR 207-208) The forecast of coal price was based upon the commodity coal prices provided by Energy Research Company, LLC. (TR 208) The projection of fuel transportation and other variable costs related to fuel delivery was updated based on the estimates obtained from L.E. Peabody & Associates, Inc. (TR 208) The Petitioners' witness Wagner testified that these sources of forward energy prices are commonly accepted in the utility industry. (TR 207)

For scenario analysis and resource planning evaluations, Seminole utilized a statistical based approach to develop alternative (i.e., high/low) natural gas price projections. Using a similar process adopted by the EIA, Seminole's alternative natural gas price forecasts stem from a statistical confidence interval representing positive/negative one standard deviation around its base case forward curve. (EXH 74)

Seminole utilized its fuel price forecasts and its alternative natural gas forecasts to prepare its original economic analysis. Seminole then utilized its updated fuel price forecasts, including its updated alternative natural gas forecasts, to prepare the updated economic analysis. (EXH 3) The Petitioners assert that the use of the updated fuel price forecast, instead of the original one, did not change the preferred resource portfolio. (EXH 90) Also, the Petitioners confirmed that Seminole utilized its fuel price forecast across all self-build and purchased power alternatives, unless a firm fuel cost was included in an RFP proposal, to ensure fairness in evaluation. (EXH 3)

[6]Generally, an escalation rate in CPVRR calculations serves as a proxy for inflation. Moody's Analytics forecasted inflation over the next 20-30 years at values ranging from 2.2 percent to 2.9 percent.

Based on the foregoing, staff recommends that Seminole's fuel price forecasts are reasonable for the purpose of economic evaluations of its potential resource options. Staff notes that the Intervenors did not proffer an alternative fuel price forecast in the proceeding for the purposes of evaluating Seminole's proposals of the Seminole Facility and Shady Hills Facility, or any other potential resource plan, and did not contest Seminole's fuel price forecasts.

Environmental Costs

The Petitioners assert that the Seminole Facility and the Shady Hills Facility will be designed with technologies to minimize air emissions. (EXH 3) The CTGs will be equipped with dry low-nitrogen oxide (NOx) combustors to control NOx emissions. (EXH 3) The HRSGs will be equipped with selective catalytic reduction systems to further reduce NOx emissions. (EXH 3) According to the Petitioners, regarding the Seminole Facility, emissions of carbon monoxide and volatile organic compounds will be limited through use of oxidation catalyst systems. (EXH 3) Emissions of other regulated air pollutants, such as sulfur dioxide and particulate matter, will be controlled through use of pipeline quality natural gas and good combustion practices. (EXH 3) In addition, the Petitioners assert that the Seminole Facility and the Shady Hills Facility will minimize greenhouse gas emissions through the use of clean-burning natural gas along with the highly efficient, combined cycle electric generating technologies. (EXH 3)

Seminole's economic sensitivity analyses include the scenarios of various Carbon Taxes based on Minnesota Public Utilities Commission's Carbon Tax assumptions. (EXH 74) These assumptions assume High, Mid, and Low Carbon Tax starting at $34.0/ton, $21.5/ton, and $9.0/ton, respectively, in 2019 and escalating afterward. (EXH 3; EXH 74) The Petitioners explain that this is the only publicly available directive information provided by its independent evaluator, Sedway Consulting, that could be used to form an adequate basis for Seminole's sensitivity analyses. (EXH 74) However, the Petitioners confirm that neither the Carbon Tax assumptions nor the Carbon Tax scenarios established upon those assumptions were used in any of the other economic sensitivity analyses, including the base case. Specifically, Seminole assumed zero Carbon Tax in deriving the portfolio evaluation results presented in Figure 13 of Seminole's Need Study, the Summary of Updated Economic Analysis. (EXH 74; EXH 3)

Based on the foregoing, staff recommends that Seminole's Carbon Tax forecast, including the underlying assumptions and the derived scenarios, as well as their utilization are reasonable for the purpose of evaluating the proposed Seminole Facility and Shady Hills Facility resource plan. Staff notes that no other Carbon Tax forecast was presented in the proceeding, and the Intervenors have not challenged Seminole's Carbon Tax assumptions/scenario nor its utilization.

Conclusion

Seminole's financial, fuel, and environmental cost estimates are reasonable. Therefore, staff recommends that the Seminole Facility and the Shady Hills Facility would provide adequate electricity at a reasonable cost.

Issue 4A: Is there a need for the proposed Seminole Combined Cycle Facility, taking into account the need for fuel diversity and supply reliability, as this criterion is used in Section 403.519(3), Florida Statutes?

Issue 4B: Is there a need for the proposed Shady Hills Combined Cycle Facility, taking into account the need for fuel diversity and supply reliability, as this criterion is used in Section 403.519(3), Florida Statute?

Recommendation: Staff recommends that the proposed addition of the Seminole Facility and Shady Hills Facility, coupled with the retirement of one of the SGS coal units, will increase Seminole's natural-gas fired winter capacity from 67.4 percent to 81.5 percent. By not equipping the Seminole Facility or Shady Hills Facility with dual-fuel capabilities, Seminole may need to rely on Florida's other electricity generators to meet their needs during natural gas curtailment events. As such, Seminole is taking measures to maintain supply availability to its natural-gas fired generating facilities. (Wright)

Position of the Parties

Seminole Issue 4A: Yes. Seminole seeks to maintain a diversified portfolio of owned and purchased generating assets with a variety of fuel types, sources and delivery options. This enables Seminole to manage fuel price stability and reliability. Seminole's decision to maintain the operation of an existing coal-fired unit will continue to provide diversification in Seminole's fuel portfolio. Additionally, Seminole is implementing a natural gas transportation plan to enhance the diversification and reliability of delivered gas supply.

Petitioners Issue 4B: Yes. Seminole seeks to maintain a diversified portfolio of owned and purchased generating assets with a variety of fuel types, sources and delivery options. This enables Seminole to manage fuel price stability and reliability. Seminole's decision to maintain the operation of an existing coal-fired unit will continue to provide diversification in Seminole's fuel portfolio. Additionally, Seminole is implementing a natural gas transportation plan to enhance the diversification and reliability of delivered gas supply.

Intervenors Issue 4A: No. Seminole's proposed MAX RISK Portfolio – called the "Clean Power Plan-Combined Cycle" Portfolio – including the SCCF, will actually <u>reduce</u> fuel diversity by increasing the State's dependence on natural gas as a generating fuel. The SCCF lacks dual-fuel capability.

Intervenors Issue 4B: No. Seminole's proposed MAX RISK Portfolio – called the "Clean Power Plan-Combined Cycle" Portfolio – including the SHCCF, will actually <u>reduce</u> fuel diversity by increasing the State's dependence on natural gas as a generating fuel. The SHCCF lacks dual-fuel capability.

Parties' Arguments

Petitioners

Petitioners argue that the Seminole Facility and Shady Hills Facility will be solely fueled by natural gas but will serve to replace expiring PPAs that were predominately natural gas-fired. (Petitioners BR 21) Petitioners maintain that adding dual-fuel capability to these units would not be cost-effective and is not necessary to maintain fuel supply reliability. (Petitioners BR 24) Petitioners assert that Seminole's decision to maintain the operation of one SGS coal-fired unit will provide continued diversification in its fuel portfolio. (Petitioners BR 21) Petitioners further aver that Seminole is implementing a natural gas transportation plan that will enhance the diversity and reliability of its natural gas supply. (Petitioners BR 22) Petitioners maintain that the Commission should, as it has in the past for new combined cycle facilities, approve this need determination despite projected increases in Seminole's reliance on natural gas-fired generation. (Petitioners BR 23)

Intervenors

Intervenors argue that Seminole's CPP/CC Portfolio, which includes the solely gas-fired Seminole Facility and Shady Hills Facility and the retirement of a coal plant, will reduce fuel diversity in Seminole's system and in Florida as whole. (Intervenors BR 29) Intervenors also note that Seminole can address its capacity and fuel-diversity needs arising from the closing of one of its SGS coal plants by acquiring additional PPAs from dual-fueled facilities like the Pasco Power Plant. (Intervenors BR 30)

Staff Analysis:

Fuel Diversity

Fuel diversity in a generation portfolio works to mitigate the effects of extreme price fluctuations, supply interruptions, and transportation instabilities. (EXH 3) Witness Wagner argued that the Seminole Facility and Shady Hills Facility are primarily serving to replace Seminole's expiring PPAs, and that retention of one of the SGS coal units will preserve Seminole's fuel diversity. Staff believes that a portfolio-level review of Seminole's generating capabilities is better suited to evaluate any changes in its system's fuel mix as a whole. (TR 211; EXH 10) Witness Kezell stated that Seminole itself subscribes to this perspective when evaluating the necessity of backup fuel in its system. (TR 169) Table 4-1 below shows the effects of the CPP/CC Portfolio on the percent of Seminole's total winter net capacity generated by its two major fuel sources, natural gas and coal.

Table 4-1
Seminole's Fuel Mix Changes

	Units	Winter 2017/2018 (Pre-CPP/CC)	Winter 2022/2023 (Post-CPP/CC)
Natural Gas Fired System Net Capacity	%	67.4	81.5
Coal Fired System Net Capacity	%	29.5	15.6
Note: Numbers may differ slightly due to rounding.			

Source: EXH 74

Intervenors' witness Sotkiewicz and Petitioners' witness Ward agree that implementation of the CPP/CC Portfolio into Seminole's system will increase Seminole's reliance on natural gas. (TR 588; TR 127) Staff agrees with both witnesses on this subject.

Witness Kezell defended Seminole's decision to not equip the Seminole Facility with dual-fuel capabilities by citing the P2021 Single Fuel Facility Analysis by Black & Veatch. (TR 169; EXH 10) The report estimated the cost of adding dual-fuel capability to the Seminole Facility to be approximately $20.3 million. (EXH 10) The P2021 Single Fuel Facility Analysis concludes that "[Seminole] will be adequately served without additional dual fuel capabilities at the portfolio level." (EXH 10) However, the report appears to draw this conclusion based on analysis of Seminole's system in a hurricane-like scenario during which electrical transmission and distribution capabilities are also impacted, which results in reduced load, as opposed to a cold-weather scenario that Seminole has experienced in the past. (EXH 10) Retrofitting dual-fuel capability into the Seminole Facility was estimated by Seminole to cost approximately $37.6 million. (EXH 79) Petitioners maintain that a similar cost analysis was not performed for the Shady Hills Facility because there are no provisions in the Tolling Agreement associated with the unit that would obligate Shady Hills to incorporate any future plant alterations for dual-fuel capabilities. (EXH 79)

According to the P2021 Single Fuel Facility Analysis, 77 percent of the natural gas combined cycle and combustion turbine units in the Florida Reliability Coordination Council are equipped with dual-fuel capabilities. (EXH 10) Witness Sotkiewicz argues that Seminole should acquire PPAs with such dual-fuel facilities to address Seminole's capacity needs. (TR 580) Staff believes that PPAs should be comprehensively evaluated and that dual-fuel capability should be one of a number of considerations.

Seminole's decision neither to equip the Seminole Facility with dual-fuel capabilities, nor to negotiate for such capability in the Shady Hills Facility, may result in Seminole relying on Florida's other electricity generators to meet Seminole's needs during natural gas curtailment events. As discussed below, Seminole is taking steps to diversify its natural gas supply.

Fuel Supply Reliability

Petitioners' witnesses Wagner and Mathur testify that the Seminole Facility and the Shady Hills Facility, respectively, will interconnect with the Florida Gas Transmission pipeline to receive their natural gas supplies. (TR 210; TR 24; EXH 3) Witness Wagner further argues that implementation of Seminole's natural gas transportation plan will improve Seminole's fuel supply reliability. (TR 212; EXH 3) Witness Sotkiewicz states that "a shift toward more natural gas likely does not cause any [supply reliability] issues." (TR 588) Staff agrees and recommends that Seminole's natural gas transportation plan will improve Seminole's fuel supply reliability because it includes contracts with four different parties that will diversify Seminole's delivered gas supply. In addition, Seminole plans to finalize contracts that will provide firm transportation of natural gas from multiple geographical locations over the life of the Seminole Facility and Shady Hills Facility.

Conclusion

Staff recommends that the proposed addition of the Seminole Facility and Shady Hills Facility, coupled with the retirement of one of the SGS coal units, will increase Seminole's natural-gas fired winter capacity from 67.4 percent to 81.5 percent. By not equipping the Seminole Facility or Shady Hills Facility with dual-fuel capabilities, Seminole may need to rely on Florida's other electricity generators to meet their needs during natural gas curtailment events. As such, Seminole is taking measures to maintain supply availability to its natural-gas fired generating facilities.

Issue 5A: Will the proposed Seminole Combined Cycle Facility provide the most cost-effective alternative available, as this criterion is used in Section 403.519(3), Florida Statutes?

Issue 5B: Will the proposed Shady Hills Combined Cycle Facility provide the most cost-effective alternative available, as this criterion is used in Section 403.519(3), Florida Statutes?

Recommendation: Yes. The proposed portfolio containing both the Seminole Facility and the Shady Hills Facility is expected to result in NPV savings of approximately $363 million in comparison to the next least cost portfolio over the study period. Therefore, staff recommends that the Seminole Facility and the Shady Hills Facility will provide Seminole's members with the most cost-effective alternatives available. (Thompson)

Position of the Parties

Seminole Issue 5A: Yes. Seminole's analyses demonstrate that the resource plan containing SCCF is the most cost-effective alternative to meet Seminole's capacity needs and would result in projected NPV savings of approximately $363 million as compared to the next ranked alternative over the study period. An independent evaluation conducted by Alan Taylor of Sedway Consulting, Inc., confirms that the selected resource plan that includes SCCF is the most cost-effective alternative.

Petitioners Issue 5B: Yes. Seminole's analyses demonstrate that the resource plan containing the SHCCF tolling agreement is the most cost-effective alternative to meet Seminole's capacity needs and would result in projected NPV savings of approximately $363 million as compared to the next ranked alternative over the study period. An independent evaluation conducted by Alan Taylor of Sedway Consulting, Inc., confirms that the selected resource plan that includes SHCCF is the most cost-effective alternative.

Intervenors Issue 5A: No. More cost-effective alternatives are available, including the Seminole-identified NO BUILD RISK Portfolio consisting of PPAs, followed by resource options that will almost certainly be more cost-effective when properly evaluated in light of actual load growth and then-current costs for gas-fired capacity, solar, and solar with storage. Because escalation rates are projected to be significantly less than Seminole's discount rate, delay will reduce CPVRRs for retail customers while minimizing customer risks.

Intervenors Issue 5B: No. More cost-effective alternatives are available, including the Seminole-identified NO BUILD RISK Portfolio consisting of PPAs, followed by resource options that will almost certainly be more cost-effective when properly evaluated in light of actual load growth and then-current costs for gas-fired capacity, solar, and solar with storage. Because escalation rates are projected to be significantly less than Seminole's discount rate, delay will reduce CPVRRs for retail customers while minimizing customer risks.

Parties' Arguments

Petitioners

The Petitioners explain that, although Seminole is not subject to the Commission's bid rule, Rule 25-22.082, F.A.C., Seminole issued a competitive RFP in March 2016, for potential power purchase options to meet its projected capacity needs.[7] (Petitioners BR 25-26) The Petitioners assert that the results of narrowing the proposals, along with utilizing modeling tools, showed that the CPP/CC Portfolio, which includes the Shady Hills Facility in 2021, the Seminole Facility in 2022, and the removal of one of the SGS coal units, was the least cost portfolio with NPV savings of approximately $363 million over the study period as compared to the next ranked portfolio. (Petitioners BR 28-29) The Petitioners argue that the results of these analyses support the conclusion that the CPP/CC Portfolio provides the most cost-effective solution for Seminole's need. (Petitioners BR 28)

Intervenors

The Intervenors argue that the CPP/CC Portfolio is not the most cost-effective alternative available to Seminole. The Intervenors assert that the No Build Portfolio, followed by additions of either self-built capacity or additional PPAs in the mid-2020s, would be more cost-effective every year from 2018 through 2026. (Intervenors BR 17) The Intervenors further assert that Seminole did not analyze an all PPA Portfolio with removal of one of its coal units. The Intervenors argue that this shows bias in Seminole's analyses in favor of the CPP/CC Portfolio and shows evidence of imprudence by Seminole. (Intervenors BR 18) The Intervenors explain that since the CPP/CC Portfolio is not the most cost-effective alternative, no economic need has been demonstrated for the Seminole Facility and the Shady Hills Facility. The Intervenors also assert that the 121 MW of capacity from the facility operated by Quantum offers a viable, competitive option to meet the needs of the retail customers. (Intervenors BR 32)

Staff Analysis:

Initial Proposals

Although not required to do so by Commission Rules, in an effort to secure the most adequate and cost-effective options for its members, Seminole conducted a RFP process, for both a self-build resource at its SGS site and market alternatives. (TR 165-166; TR 170-171; TR 399-400) As discussed in Issues 3A and 3B, for the self-build alternative, witness Kezell testified that Seminole retained Black & Veatch to help evaluate numerous power generation technologies as potential future resources before selecting combined cycle technology. (TR 165) Seminole initiated a power island equipment purchase bidding process, followed by an engineering, procurement, and construction services bidding process, to develop accurate self-build cost estimates which would compete with market alternatives. (TR 166) Witness Kezell stated that Seminole evaluated several different technologies from three different vendors: General Electric, Mitsubishi, and Siemens. (TR 166) In February 2016, witness Kezell asserted that Seminole issued an RFP to these three vendors, and only General Electric and Mitsubishi responded with compliant bids. (TR 166) Each vendor submitted two proposals: one for a 1x1 configuration and one for a 2x1 configuration. (TR 166) Witness Kezell maintained that these four proposals were

[7]The Petitioners' brief erroneously referenced Rule 25-17.082 instead of Rule 25-22.082. (Petitioners BR 25)

evaluated along with the market alternatives and, ultimately, General Electric's proposal for the 2x1 configuration was found to be the most economic option. (TR 166) As discussed in Issues 3A and Issue 3B, witness Ward stated that Seminole received a competitive market rate from the original equipment manufacturers and engineering, procurement, and construction companies for the self-build alternative. (TR 128)

As discussed by the Petitioners' witness Peters, Seminole issued an RFP on March 31, 2016, outlining that it was looking for up to 600 MW starting in June 2021, with needs up to 1,000 MW by June 2022. (TR 402) Seminole's RFP was open to all parties, resulting in over 200 proposals that spread across a wide spectrum of alternatives. (TR 402-404; TR 410) As a result, Seminole brought together various in-house subject matter experts to evaluate the proposals. (TR 404) Witness Taylor, an independent evaluator and President of Sedway Consulting, was also retained by Seminole to provide independent monitoring and evaluation services during Seminole's RFP processes, overseeing both the self-build and market alternative RFP processes. (TR 505)

Seminole utilized Planning and Risk and System Optimizer software tools to select which generation/PPAs provided the greatest overall economic value within an entire portfolio with varying combinations of start dates, term lengths, and MW sizes. (TR 406) Witness Diazgranados testified that System Optimizer and Planning and Risk are industry-recognized utility tools. (TR 446-447) According to witness Diazgranados, System Optimizer is used to develop an optimal resource mix to satisfy future needs. (TR 446) Witness Diazgranados stated that Planning and Risk is a detailed production cost model which commits resources in each hour over the thirty-three year study period from 2018-2051, based on costs and operational constraints. (TR 447) Witness Peters stated that during the process of narrowing down the number of proposals to a manageable short-list, certain bids were removed from consideration for non-economic reasons such as: transmission availability, fuel accessibility and availability, build and construction risks, technological/commercial risks, environmental factors, credit capabilities, term flexibility, and scheduling flexibility. (TR 406) Staff notes that Quantum, one of the Intervenors, responded to Seminole's RFP and was included in the shortlist of alternatives, but ultimately was not selected during the evaluation process. (TR 418; TR 433; EXH 27) Quantum's facility offers 121 MW of capacity while Seminole's RFP outlined that Seminole was looking for up to 600 MW starting in June 2021, with needs up to 1,000 MW by June 2022. (TR 402) The Intervenors argue that Quantum offers a viable, competitive option to meet Seminole's member consumers needs. However, Quantum was included in an Alternate No Build Risk: All PPA Portfolio, and the record shows that the portfolio including the Quantum facility was approximately $770 million NPV less cost-effective than the CPP/CC Portfolio over the study period. (TR 710; EXH 83; EXH 92) Due to this, staff recommends that the Intervenors' argument is not persuasive.

According to witness Taylor, Sedway Consulting's independent evaluation consisted of overseeing both Seminole's self-build and market alternative RFP processes. (TR 505) With the self-build RFP process, Sedway Consulting was involved with the monitoring and evaluation of proposals that might be selected in developing a resource that Seminole would own and operate. (TR 505) Also, Witness Taylor testified that Sedway Consulting monitored Seminole's market alternatives RFP process. (TR 505-506) In doing so, witness Taylor reviewed Seminole's RFP processes, and performed a parallel and independent economic evaluation of the self-build and PPA proposals submitted in response to Seminole's RFPs. (TR 506) As with Seminole, Sedway Consulting took into consideration non-economic factors as well. Proposals from one bidder were removed because development efforts were in an early stage which translated into greater risk and uncertainty associated with these units. (EXH 51) Ultimately, witness Taylor concluded that Seminole's best option for meeting its long-term capacity needs was a combination of self-build and market alternatives. (TR 506-507) This included the Seminole Facility and the Shady Hills Facility, as well as a combination of PPAs, and a decision to remove from service one of the SGS coal units. (TR 506-507) Witness Taylor testified that Seminole's evaluation process was conducted fairly, and that the market alternative proposals and Seminole's self-build resource were evaluated on an equal footing. (TR 510) Because the Petitioners conducted RFP processes in order to evaluate various alternatives to fulfill Seminole's need, and hired an independent evaluator to ensure that the most cost-effective alternatives were selected, staff recommends that the Petitioners' analyses of alternatives were thorough.

Portfolios

Based on Seminole's economic and risk evaluation of all available alternatives, four portfolios of generation resources were developed to fulfill Seminole's need. (TR 444; TR 446) Witness Diazgranados asserted that the first iteration ran through System Optimizer, the SGS 2x1 Portfolio, was to develop a portfolio for the need starting in winter of 2022 with all resources available. (TR 446) The next portfolio developed, the Limited Build Risk: Shady Hills Portfolio (Limited Build Portfolio), was a limited build, allowing one 1x1 combined cycle unit to be built. (TR 446) The next portfolio developed, the No Build Portfolio, consisted of only PPAs. (TR 446) Last, the CPP/CC Portfolio was developed taking into account removal of one coal unit from service. (TR 446) According to witness Diazgranados, removing a coal unit from service for the CPP/CC Portfolio was due to regulatory uncertainty and long-term economics of coal-fired generation. (TR 446) According to the record, the CPP/CC Portfolio, containing the Seminole Facility and the Shady Hills Facility, was approximately $363 million, in NPV revenue requirement terms, less expensive than the next least cost portfolio over the study period. (TR 451) The record further indicates that each portfolio also contained generic combined cycle and combustion turbine units in later years to backfill as PPAs expired. (EXH 74; EXH 78) Table 5-1 below summarizes each of the portfolios.

Table 5-1
Portfolios

Year	SGS 2x1	Limited Build	No Build	CPP/CC
2021	Multiple PPAs	Shady Hills Facility Multiple PPAs	Multiple PPAs	Shady Hills Facility Multiple PPAs
2022	Seminole Facility			Seminole Facility Retire SGS Unit
2023				
2024		Additional PPA	Additional PPA	Additional PPA
2025				
2026				
2027+	Generic CCs/CTs	Generic CCs/CTs	Generic CCs/CTs	Generic CCs/CTs

Source: EXH 74

SGS Coal Unit Removal

Due to regulatory uncertainty and long-term economics of coal-fired generation, Seminole decided to remove one of its 664 MW SGS coal units from service in the CPP/CC Portfolio. (TR 446) Staff notes that these dockets are not for approval of the removal of one of Seminole's SGS coal units. The Petitioners state that the cost of maintaining and satisfying operational requirements associated with coal units make them a less attractive option given the high efficiencies of the models of combined cycle generation and low natural gas price projections. (EXH 74) Witness Taylor asserted that coal-fired resources are fairly inflexible in some aspects, for example, their inability to shut down at night and start back up in the morning. (TR 555-556) Because these units would have to be carried through the night, unlike natural-gas fired combined cycle generation, staff recommends that witness Taylor's assertion is persuasive. The Seminole Facility will have significant flexibility in that the "turndown" capability will allow the gas turbines to meet their required emissions levels, while firing the turbines down to as low as 25 percent of their full-fire levels. This, in turn, will allow the Seminole Facility to remain operational during low load periods typically experienced at night. (TR 166) This will allow it to avoid the thermal stress, wear, and high emission concentrations typically associated with a shut-down/start-up cycle, as can be associated with coal units. (TR 166-167) The Intervenors assert that Seminole did not evaluate an all PPA Portfolio with removal of a coal unit. While this is true, staff would note that all three remaining portfolios proposed by the Petitioners did not include the removal of a coal unit from the analyses, and there is no requirement to do so. As later shown in Table 5-2, of these three, the No Build Portfolio is still the most expensive alternative over the study period.

Board of Trustees' Decision

Seminole is owned by its members and governed by a Board of Trustees. Each of Seminole's members has two voting representatives and one alternate representative on Seminole's Board of Trustees. (TR 54) Public witness Duncan and Public witness Hackett, two members of Seminole's Board of Trustees, testified at the hearing held on March 21, 2018, in support of approval of the CPP/CC Portfolio which includes the Seminole Facility and the Shady Hills Facility. (TR 7-14) Ultimately, Seminole's Board of Trustees unanimously deemed the CPP/CC

Portfolio that includes both the Seminole Facility and the Shady Hills Facility, as the best portfolio overall to meet Seminole's members needs over the study period. (TR 450-451) Also, according to witness Ward, Seminole's Board of Trustees made a determination that the No Build Portfolio is not a portfolio they wished to pursue based on reliability and overall cost. (TR 107)

Economic Analyses

As previously discussed, the RFP processes resulted in four combinations of portfolios for evaluation by Seminole. (TR 446) Because these portfolios represent the least cost alternatives based on the Petitioners' economic analyses, staff recommends that these portfolios represent reasonable alternative scenarios for cost-effectively meeting the needs of Seminole's members over the study period. Seminole's annual revenue requirement analysis provides the total cost for each portfolio over the study period from 2018 through 2051. (EXH 74; EXH 83) Table 5-2 below shows the total cost associated with each portfolio.

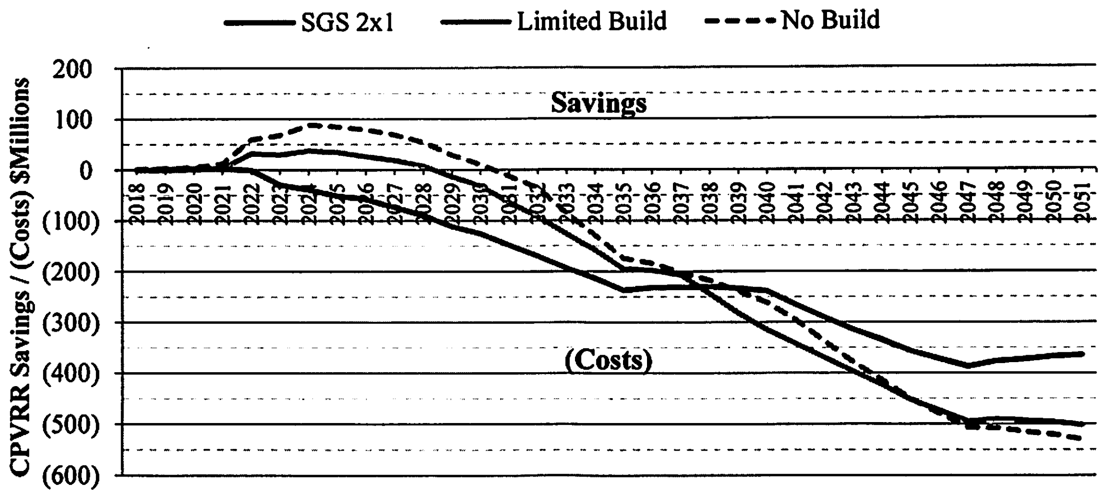
Table 5-2
Total Revenue Requirements ($million NPV)

Portfolio	Total	Difference from the CPP/CC Portfolio
SGS 2x1 Portfolio	20,982	(363)
Limited Build Portfolio	21,120	(502)
No Build Portfolio	21,148	(530)
CPP/CC Portfolio	20,618	-
Note: Numbers may differ slightly due to rounding.		

Source: EXH 74; EXH 83

As shown in Table 5-2 above, the CPP/CC Portfolio, which includes both the Seminole Facility and the Shady Hills Facility, is the least cost portfolio and is approximately $363 million less expensive than the SGS 2x1 Portfolio, the next least cost portfolio. (TR 450-451) Staff notes that the SGS 2x1 Portfolio and the Limited Build Portfolio, each including both SGS coal units, are also more cost-effective than the No Build Portfolio over the study period. As indicated in the record, due to regulatory uncertainty and long-term economics of coal-fired generation, Seminole decided to consider a portfolio with removal of one of the coal units, the CPP/CC Portfolio. (TR 446) Once the coal unit was removed, the record indicates that a portfolio including the Seminole Facility and the Shady Hills Facility was the optimal portfolio identified via System Optimizer. (TR 447) Based on the record, the CPP/CC Portfolio, including both the Seminole Facility and the Shady Hills Facility, ultimately was the most cost-effective portfolio over the study period. Figure 5-1 below, shows CPVRR savings and costs for each portfolio as compared to the CPP/CC Portfolio.

Figure 5-1
Annual CPVRR Comparison to the CPP/CC Portfolio



Source: EXH 74, EXH 83

As shown above, the No Build Portfolio is expected to produce CPVRR savings through 2031. (EXH 74; EXH 83) However, the No Build Portfolio is expected to be over $500 million CPVRR more expensive than the CPP/CC Portfolio over the study period. (EXH 74; EXH 83) The next least cost portfolio over the study period is expected to be the SGS 2x1 Portfolio. (EXH 74; EXH 83)

The Intervenors' witness Sotkiewicz argued that the CPP/CC Portfolio is not the most cost-effective alternative available to Seminole, and that delaying the Seminole Facility or the Shady Hills Facility will reduce CPVRRs to customers. (TR 603) According to witness Ward, the No Build Portfolio is the least cost portfolio over approximately the first seven years of the study period. (TR 128) However, the Petitioners state that Seminole evaluated both the total revenue requirements for a period of 2018 through 2051, as well as a period of 2018 through 2027, and that the CPP/CC Portfolio was the most cost-effective, risk-managed resource plan for both periods. (EXH 78) Although the No Build Portfolio has NPV savings of approximately $69 million in the 2018 through 2027 time period in comparison to the CPP/CC Portfolio, staff disagrees with witness Sotkiewicz's argument. Staff recommends that witness Ward's argument is persuasive because the No Build Portfolio has the additional risk and uncertainty associated with having to go back into the market for replacement resources as the PPAs expire. Staff notes that the No Build Portfolio also has potential additional transmission costs and risks associated with having to transfer energy through multiple areas for Seminole's member load.

The Petitioners also argue that it is an industry standard practice to evaluate new generation facilities over a reasonable life expectancy, and that most natural gas generating facilities have a life of 30 plus years. (EXH 78) Because Seminole was evaluating new generation facilities (both owned and PPAs), staff recommends that it is appropriate to have a study period that would cover the life expectancy of these units, and recommends that the Petitioners argument is persuasive. The Petitioners state that traditionally, revenue requirements for cooperative owned generation decline over the life of the facility, whereas PPA pricing is usually flat or even escalating. (EXH 78) Witness Sotkiewicz testified that delaying the in-service dates of the Seminole Facility and the Tolling Agreement for the Shady Hills Facility will improve the CPVRR and rate impacts to customers. (TR 603) However, witness Ward stated that Seminole is choosing not to delay the Seminole Facility to fulfill its needs with PPAs during the first ten years of the study period due to having received a competitive market rate from the original equipment manufacturers and engineering, procurement and construction companies to build the Seminole Facility in the 2022 timeframe. (TR 128) He further stated that he would not be able to say with certainty that the same cost would be available in another seven to ten years. (TR 128) Witness Diazgranados also testified that if building either of the facilities were delayed until later in the study period, such delay would not reduce the CPVRR of payments from customers. (TR 481) She further testified that the No Build Portfolio includes generic combustion turbine units as backfill units as PPAs expire, using Seminole's two percent escalation rate, which is more costly over the study period. (TR 481)

Staff is not persuaded by the Intervenors' recommendation of a short term approach because this viewpoint would favor building a less efficient combustion turbine facility, since it is initially less expensive and quicker to build, over a more efficient combined cycle facility. Staff recommends and the record shows that the CPP/CC Portfolio containing the Seminole Facility and the Shady Hills Facility is the most cost-effective portfolio over the study period, and staff recommends that the Seminole Facility and the Shady Hills Facility are the best alternatives to reliably meet Seminole's members' and member-consumers' needs.

Conclusion

The proposed portfolio containing both the Seminole Facility and the Shady Hills Facility is expected to result in NPV savings of approximately $363 million in comparison to the next least cost portfolio over the study period. Therefore, staff recommends that the Seminole Facility and the Shady Hills Facility will provide Seminole's members with the most cost-effective alternatives available.

Issue 5C: Did Seminole Electric Cooperative, Inc. accurately and appropriately evaluate reasonable alternative scenarios for cost-effectively meeting the needs of its customers over the relevant planning horizon for the Seminole Combined Cycle Facility?

Issue 5D: Did Seminole Electric Cooperative, Inc. accurately and appropriately evaluate reasonable alternative scenarios for cost-effectively meeting the needs of its customers over the relevant planning horizon for the Shady Hills Combined Cycle Facility?

Recommendation: Yes. As discussed in Issues 5A and 5B, Seminole solicited RFPs to fulfill its capacity need and hired an independent evaluator to ensure that it selected the best overall alternatives. (Thompson)

Position of the Parties

Seminole Issue 5C: Yes. When removing a coal unit was assumed in Seminole's economic analyses, the model selected new units as components of portfolios it identified as potentially cost-effective. Similarly, Mr. Taylor's independent analysis identified new units as components of the most cost-effective plan. No evidence of record suggests an "All-PPA" portfolio would be cost-effective under any scenario. Additionally, an All-PPA portfolio would force Seminole to rely on resources in balancing areas where the power is not needed.

Petitioners Issue 5D: Yes. When removing a coal unit was assumed in Seminole's economic analyses, the model selected new units as components of portfolios it identified as potentially cost-effective. Similarly, Mr. Taylor's independent analysis identified new units as components of the most cost-effective plan. No evidence of record suggests an "All-PPA" portfolio would be cost-effective under any scenario. Additionally, an All-PPA portfolio would force Seminole to rely on resources in balancing areas where the power is not needed.

Intervenors Issue 5C: No. Seminole did not accurately or appropriately evaluate all reasonable alternative power supply options for meeting the needs of its Member Cooperatives and the retail customers who depend on Seminole. Even when Seminole's own analyses showed that the NO BUILD RISK Portfolio would save approximately $136 Million in CPVRR terms from 2018 through 2027, Seminole neither attempted to negotiate for later in-service dates for the SCCF or SHCCF, and did not consider other available alternatives.

Intervenors Issue 5D: No. Seminole did not accurately or appropriately evaluate all reasonable alternative power supply options for meeting the needs of its Member Cooperatives and the retail customers who depend on Seminole. Even when Seminole's own analyses showed that the NO BUILD RISK Portfolio would save approximately $136 Million in CPVRR terms from 2018 through 2027, Seminole neither attempted to negotiate for later in-service dates for the SCCF or SHCCF, and did not consider other available alternatives.

Parties' Arguments

Petitioners

The Petitioners assert that Seminole evaluated over 200 proposals in response to its RFP and developed reasonable portfolios for evaluation. (Petitioners BR 32) The Petitioners argue that there is no basis to suggest that the type of "No Build-All-PPA" portfolio advocated by the Intervenors would be cost-effective under any scenario, whether or not a coal unit is assumed to be taken out of service. (Petitioners BR 32) The Petitioners further argue that an all PPA Portfolio, as recommended by the Intervenors, would force Seminole to rely on PPA sources in balancing areas where the power is not needed to serve Seminole's load; therefore, requiring Seminole to wheel it to a different balancing area. (Petitioners BR 32) Seminole argues that this would increase costs and raise reliability concerns given the fact that Seminole is a transmission-dependent wholesale provider. (Petitioners BR 33-34)

Intervenors

The Intervenors argue that Seminole used inflation rates reflecting the annual increases in costs to build new facilities that are below Seminole's cost of borrowing reflected in its discount rate of six percent. (Intervenors BR 22) The Intervenors claim that delay will improve the CPVRRs, thus delaying the need for the Seminole Facility and the Shady Hills Facility. (Intervenors BR 22) The Intervenors further claim that Seminole failed to try to obtain both medium-term benefits available from the No Build Portfolio, through at least 2026, and to similarly realize the CPVRR benefits that should be available through deferring additional capacity commitments. (Intervenors BR 22) The Intervenors state that Seminole did not try to negotiate for later in-service dates with General Electric or Shady Hills, and suggest that the Commission should deny both petitions. (Intervenors BR 23)

Staff Analysis: As discussed in Issues 5A and 5B, Seminole solicited RFPs for both self-build and market alternatives for its capacity need. Seminole's subject matter experts and its independent evaluator, witness Taylor, evaluated and narrowed down the responses and utilized modeling tools to further evaluate the alternatives. The Petitioners concluded that the CPP/CC Portfolio, including both the Seminole Facility and the Shady Hills Facility, was the best portfolio to meet Seminole's needs. As previously discussed, staff recommends that the portfolios presented were reasonable, and were evaluated over the relevant planning horizon.

Conclusion

As discussed in Issues 5A and 5B, Seminole solicited RFPs to fulfill its capacity need and hired an independent evaluator to ensure that it selected the best overall alternatives. Therefore, staff recommends that the Petitioners accurately and appropriately evaluated reasonable alternative scenarios for cost-effectively meeting the needs of Seminole's customers over the relevant planning horizon for the Seminole Facility and the Shady Hills Facility.

Issue 6A: Based on the resolution of the foregoing issues and other matters within its jurisdiction which it deems relevant, should the Commission grant Seminole Electric Cooperative, Inc.'s petition to determine the need for the proposed Seminole Combined Cycle Facility?

Issue 6B: Based on the resolution of the foregoing issues and other matters within its jurisdiction which it deems relevant, should the Commission grant Seminole and Shady Hills Energy Center, LLC's joint petition to determine the need for the proposed Shady Hills Combined Cycle Facility?

Recommendation: Yes. (Thompson)

Position of the Parties

Seminole Issue 6A: Yes. The SCCF is part of a resource plan that will ensure that Seminole can meet its Members' needs at a reasonable cost. The results of the RFP and resource planning processes demonstrate that the selected plan is the most cost-effective, risk-managed alternative. Seminole and its Members utilize reasonably available renewable resources and conservation programs. However, a significant capacity need remains and the selected resource plan is the least cost alternative to meet that need.

Petitioners Issue 6B: Yes. The SHCCF is part of a resource plan that will ensure that Seminole can meet its Members' needs at a reasonable cost. The results of the RFP and resource planning processes demonstrate that the selected plan is the most cost-effective, risk-managed alternative. Seminole and its Members utilize reasonably available renewable resources and conservation programs. However, a significant capacity need remains and the selected resource plan is the least cost alternative to meet that need.

Intervenors Issue 6A: No. Seminole has not credibly demonstrated that it has either a reliability need or an economic need for its proposed MAX RISK Portfolio, including the SCCF and SHCCF. Even assuming the accuracy of Seminole's dubious load forecasts, the MAX RISK Portfolio is not the most cost-effective alternative available and would reduce fuel diversity. Seminole's proposals would unnecessarily impose $13 BILLION in cost risk on customers. The Commission should deny both petitions.

Intervenors Issue 6B: No. Seminole has not credibly demonstrated that it has either a reliability need or an economic need for its proposed MAX RISK Portfolio, including the SCCF and SHCCF. Even assuming the accuracy of Seminole's dubious load forecasts, the MAX RISK Portfolio is not the most cost-effective alternative available and would reduce fuel diversity. Seminole's proposals would unnecessarily impose $13 BILLION in cost risk on customers. The Commission should deny both petitions.

Parties' Arguments

Petitioners

The Petitioners state that, for the reasons discussed in Issues 1A through 5D, the Commission should grant the petitions for determination of need for the Seminole Facility and the Shady Hills Facility because the analyses presented demonstrate that these two facilities are needed to meet the electrical demands of Seminole and its members and otherwise satisfy all of the criteria set forth in section 403.519, F.S. (Petitioners BR 34) The Petitioners argue that non-approval would mean that Seminole's members and member-consumers would be denied the most cost-effective, risk managed power supply solution, and Seminole's required reserve margin would fall below the minimum reserve level in 2021. (Petitioners BR 34-35) The Petitioners assert that the adverse impact would be $530 million of additional NPV revenue requirements without consideration of transmission impacts, as well as continuation of service of the coal unit, if both projects were to be denied. (Petitioners BR 35) The Petitioners explain that if only the Seminole Facility is denied, the impact would be approximately $502 million, along with the continuation of the coal unit. (Petitioners BR 35) The Petitioners further explain that if only the Shady Hills Facility is denied, the impact would be approximately $363 million, along with the continuation of service of the coal unit. (Petitioners BR 36)

Intervenors

The Intervenors argue that Seminole's load forecasts are unproven and questionable, that the No Build Portfolio is the more cost-effective alternative for meeting the retail customers' needs, and that adding the capacity represented by the Seminole Facility and the Shady Hills Facility will uneconomically duplicate capacity. (Intervenors BR 33-34) The Intervenors further argue that the CPP/CC Portfolio will increase Seminole's dependence on natural gas. (Intervenors BR 34) The Intervenors suggest that the Commission deny the petitions for need determination for both the Seminole Facility and the Shady Hills Facility. (Intervenors BR 34)

Staff Analysis: Pursuant to Section 403.519, F.S., the Commission is the sole forum for the determination of need for major new power plants. In making its determination, the Commission must take into account the need for electric system reliability and integrity, the need for adequate electricity at a reasonable cost, the need for fuel diversity and supply reliability, and whether the proposed plant is the most cost-effective alternative available. The Commission must also expressly consider whether renewable generation or conservation measures taken by or reasonably available to the utility might mitigate the need for the proposed plant. The Commission's decision on a need determination petition must be based on the facts as they exist at the time of the filing with the underlying assumptions tested for reasonableness.

As shown in Issues 1A through 5D, the record supports an overall need for the Shady Hills Facility in 2021 and the Seminole Facility in 2022. The following summarizes the previous issues:

1. The Petitioners have demonstrated that Seminole has a system need for capacity additions beginning in 2021 to meet its 15 percent reserve margin criterion.

2. No cost-effective DSM or renewable resources have been identified that could mitigate the need for the Seminole Facility or the Shady Hills Facility.

3. The Seminole Facility and the Shady Hills Facility are expected to provide adequate electricity at a reasonable cost to Seminole's members and member-consumers.

4. The Seminole Facility, the Shady Hills Facility, and the retirement of one of the SGS coal units will increase Seminole's reliance on natural gas.

5. The CPP/CC Portfolio containing the Seminole Facility and the Shady Hills Facility is expected to result in NPV savings of approximately $363 million in comparison to the next least cost portfolio and, therefore, is the most cost-effective alternative.

Conclusion

Based on the foregoing, staff recommends that the Commission grant the Petitioners' requested determination of need. It is prudent for a utility to continue to evaluate whether it is in the best interests of its ratepayers for a utility to participate in a proposed power plant before, during, and after construction of a generating unit. If conditions change from those presented at the need determination proceeding, then a prudent utility would be expected to respond appropriately.

Issue 7A: Should Docket No. 20170266-EC be closed?

Issue 7B: Should Docket No. 20170267-EC be closed?

Recommendation: Yes. Upon issuance of an order on Seminole's petition to determine the need for the proposed Seminole Combined Cycle Facility and the Petitioners' petition to determine the need for the proposed Shady Hills Combined Cycle Facility, these dockets should be closed after the time for filing an appeal has run. (Dziechciarz, Murphy)

Position of the Parties

Seminole Issue 7A: Yes. Upon issuance of a final order granting Seminole's petition for need determination for the SCCF, Docket No. 20170266-EC should be closed.

Petitioners Issue 7B: Yes. Upon issuance of a final order granting the joint petition of Seminole and SHEC for need determination for the SHCCF, Docket No. 20170267-EC should be closed.

Intervenors Issue 7A: Yes. Docket No. 20170266-EC should be closed when the Commission's order denying Seminole's petition for determination of need for the SCCF becomes final and no longer subject to appeal.

Intervenors Issue 7B: Yes. Docket No. 20170267-EC should be closed when the Commission's order denying Seminole's and Shady Hills' joint petition for determination of need for the SHCCF becomes final and no longer subject to appeal.

Staff Analysis: Upon issuance of an order on Seminole's petition to determine the need for the proposed Seminole Combined Cycle Facility and the Petitioners' petition to determine the need for the proposed Shady Hills Combined Cycle Facility, these dockets should be closed after the time for filing an appeal has run.