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Commission Conference Agenda
December 3, 2015

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Office of Telecommunications (Williams) CW
Office of the General Counsel (Lherisson) BX KEY

RE: Request for Approval of Transfer and Name Change on Certificate of Authority No. 8845 from Atlantic Broadband Enterprise, LLC to Atlantic Broadband (Miami), LLC.

AGENDA: 12/3/2015 - Consent Agenda - Proposed Agency Action - Interested Persons May Participate

SPECIAL INSTRUCTIONS: None

Please place the following request for approval of transfer and name change on Certificate of Authority No. 8845 from Atlantic Broadband Enterprise, LLC to Atlantic Broadband (Miami), LLC on the consent agenda for approval.

DOCKET NO.	COMPANY NAME	CERT. NO.
150205-TX	Atlantic Broadband Enterprise, LLC	8845
	Atlantic Broadband (Miami), LLC	

The Commission is vested with jurisdiction in this matter pursuant to Section 364.335, Florida Statutes. The Certificate of Authority authorizes Atlantic Broadband (Miami), LLC to provide Telecommunications Services in the State of Florida as a Telecommunications Company as defined by Section 364.02(13), 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.

FILED NOV 18, 2015
DOCUMENT NO. 07302-15
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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

SY DB CRDB MC ALM

FROM: Division of Accounting and Finance (Yeazel, Buys, Cicchetti)
Office of the General Counsel (Barrera) JSC

RE: Docket No. 150231-GU – Application for authority to issue debt security, pursuant to 366.04, F.S., and Chapter 25-8, F.A.C., by Florida City Gas.

AGENDA: 12/03/15 – Consent Agenda – Final Action - Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Please place the following securities application on the consent agenda for approval.

Docket No. 150231-GU – Application for authority to issue debt security, pursuant to 366.04, F.S., and Chapter 25-8, F.A.C., by Florida City Gas.

Florida City Gas (Company) seeks authority to finance its on-going cash requirements through its participation and borrowings from and investments in AGL Resources Inc.'s (AGLR) Utility Money Pool during 2016. Florida City Gas is a division of Pivotal Utility Holdings, Inc., which is a wholly-owned subsidiary of AGLR. The maximum aggregate short-term borrowings by Pivotal Utility Holdings, Inc.'s three utilities (Elizabethtown Gas, Elkton Gas, and Florida City Gas) from the Utility Money Pool during 2016 will not exceed $800 million. Florida City Gas states that its share of these borrowings will not exceed $250 million.

In connection with this application, Florida City Gas confirms that the capital raised pursuant to this application will be used in connection with the regulated natural gas operations of Florida City Gas and not the unregulated activities of the utility or its affiliates.

Staff has reviewed the Company's projected capital expenditures. The amount requested by the Company exceeds its expected capital expenditures. The additional amount requested exceeding the projected capital expenditures allows for financial flexibility for the purposes enumerated in the Company's petition as well as unexpected events such as hurricanes, financial market disruptions, and other unforeseen circumstances. Staff believes the requested amounts are appropriate. Staff recommends the Company's petition to issue securities be approved.

For monitoring purposes, this docket should remain open until April 28, 2017, to allow the Company time to file the required Consummation Report.

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Office of the General Counsel (Page) PHP SMC
Division of Economics (Rome, Draper) CRR ESD PD

RE: 150241-PU - Proposed amendments to Rules 25-6.093, Information to Customers; 25-6.097, Customer Deposits; 25-6.100, Customer Billings; 25-7.079, Information to Customers; 25-7.083, Customer Deposits; and 25-7.085, Customer Billing, F.A.C.

AGENDA: 12/03/15 – Regular Agenda – Rule Proposal - Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Patronis

RULE STATUS: Proposal May Be Deferred

SPECIAL INSTRUCTIONS: None

Case Background

Rules 25-6.093, Information to Customers, 25-6.097, Customer Deposits, 25-6.100, Customer Billings, 25-7.079, Information to Customers, 25-7.083, Customer Deposits, and 25-7.085, Customer Billing, Florida Administrative Code (F.A.C.), set forth the requirements for investor owned electric and gas utilities on billings, deposits, and information to customers. The rules implement Section 366.05 and Section 366.95, Florida Statutes (F.S.).

Paragraph 366.05(1)(b), F.S., addresses tiered utility rates based on levels of usage and varied billing periods. Paragraphs 366.05(1)(c) and (d), F.S., pertain to customer deposits and customer information for electric and gas utilities. Paragraphs 366.95(4)(a) and (b), F.S., require billing notices for electric utilities that have obtained a financing order for nuclear assets and caused nuclear asset recovery bonds to be issued.

Staff initiated this rulemaking to conform the rules to the recent amendments to Section 366.05 and Section 366.95, F.S., and to clarify and simplify the rules and delete unnecessary and redundant rule language. The Commission's Notice of Development of Rulemaking was published in the Florida Administrative Register (F.A.R.) on September 25, 2015, in Volume 41, Number 187. There were no requests for a rule development workshop, so no workshop was held. However, comments were received from Gulf Power (Gulf), Tampa Electric Company (TECO), Duke Energy (Duke), the Office of Public Counsel (OPC), Florida Power & Light Company (FPL) and Peoples Gas System (Peoples).

This recommendation addresses whether the Commission should propose the amendment of Rules 25-6.093, 25-6.097, 25-6.100, 25-7.079, 25-7.083, and 25-7.085, F.A.C. The Commission has jurisdiction pursuant to Section 120.54, F.S., and Section 366.05, F.S.

Discussion of Issues

Issue 1: Should the Commission propose the amendment of Rules 25-6.093, 25-6.097, 25-6.100, 25-7.079, 25-7.083, and 25-7.085, F.A.C.?

Recommendation: Yes. The Commission should propose the amendment of Rules 25-6.093, 25-6.097, 25-6.100, 25-7.079, 25-7.083, and 25-7.085, F.A.C., as set forth in Attachment A. (Page, Rome, Draper).

Statutory Amendments

In the 2015 session, the Legislature amended Section 366.05, and added Section 366.95, F.S., to impose new requirements on electric and gas utilities. These new requirements are summarized below.

Paragraph 366.05(1)(b), F.S. states that if the Commission authorizes a public utility to charge tiered rates based upon levels of usage and to vary its regular billing period, the utility may not charge a customer a higher rate because of an increase in usage attributable to an extension of the billing period. The regular meter reading date may not be advanced or postponed more than 5 days for routine operating reasons without prorating the billing for the period.

Subparagraph 366.05(1)(c)1., F.S., states that effective January 1, 2016, a utility may not charge or receive a deposit for existing accounts in excess of 2 months of average actual charges calculated by adding the monthly charges from the 12-month period immediately before the date any change in the deposit amount is sought, dividing this total by 12, and multiplying the result by 2. For a new service request, subparagraph 366.05(1)(c)2., F.S., provides that the total deposit shall not exceed 2 months of projected charges, calculated by adding the 12 months of projected charges, dividing this total by 12, and multiplying the result by 2.

Paragraph 366.05(1)(d), F.S., provides that if a utility has more than one rate for any customer class, it must notify each customer in that class of the available rates and explain how the rate is charged to the customer. If a customer contacts the utility seeking assistance in selecting the most advantageous rate, the utility must provide good faith assistance to the customer.

Paragraph 366.95(4)(a), F.S., states that customer billings must explicitly reflect that a portion of the charges on the bill represents nuclear-asset recovery charges if a financing order has been approved by the Commission and issued to the electric utility. Paragraph 366.95(4)(b), F.S., requires the electric utility to include the nuclear asset recovery charge on each customer's bill as a separate line item titled "Asset Securitization Charge" and state both the rate and the amount of the charge on each bill.

Staff is recommending that the Commission propose the amendment of Rules 25-6.093, 25-6.097, 25-6.100, 25-7.079, 25-7.083, and 25-7.085, F.A.C., as set forth in Attachment A to implement these statutory changes. Staff is also recommending a number of amendments to update and clarify the rules.

Electric Utilities

Rule 25-6.093, F.A.C.

Rule 25-6.093(3)(a), F.A.C., Information to Customers, states that by bill insert or other appropriate means of communication, the utility shall give to each of its customers a summary of major rate schedules which are available to the class of which that customer is a member. Staff recommends amendments to Rule 25-6.093(3)(a), F.A.C., to conform the rule to paragraph 366.05(1)(d), F.S.

FPL commented that the information to customers may be provided in paper or electronic form and may consist of a summary of all available electrical rates that are available to the class of which that customer is a member. Staff believes that allowing the utility to designate the bill insert as paper or electronic will ensure that the term "bill insert" is up to date with current practices and processes. According to FPL, the use of the term "summary of major rate schedules" would result in a substantial expansion of the information that must be provided to customers via bill insert. FPL suggests that a summary of all available rates be provided to customers, but not all supporting schedules such as the tariffs. Staff agrees that the summary of available rates would be beneficial to both the utility and customers and recommends that this term be included in the amendments to Rule 25-6.093, F.A.C.

Staff recommends amendments to Rule 25-6.093, F.A.C., that by paper or electronic bill insert or other means agreed to by both the customer and the utility, the utility shall give to each of its customers a summary of all available electrical rates applicable to the customer's class. Gulf commented that "means agreed to by both the customer and the utility" could create additional work to communicate with customers. Gulf suggested that the amendment state that by billing statement, website, electronic notification or other appropriate means of communication the utility shall give to each of its customers the rate schedules that are available to the customer. Staff does not recommend the phrase "appropriate means of communication" because it is vague and open to a wide range of possible interpretation. Staff believes that Gulf's suggestion to add the terms "billing statement, website and electronic notification" to the list of means by which utilities can provide rate information to customers is a reasonable implementation of paragraph 366.05(1)(d), F.S. Therefore, staff recommends that this suggested language be included in the amendments to Rule 25-6.093(3)(a), F.A.C.

Paragraph 366.05(1)(d), F.S., states that if a utility has more than one rate for any customer class, it must notify each customer in that class of available rates and explain how the rate is charged to the customer. The statute states that if a customer contacts the utility seeking assistance in selecting the most advantageous rate, the utility must provide good faith assistance to the customer.

Staff believes that Rule 25-6.093, F.A.C., reiterates the provisions of paragraph 366.05(1)(d), F.S., regarding customer information and the obtainment of the most advantageous rate for the customer's service requirements. Pursuant to paragraph 120.545(1)(c), F.S., the Joint Administrative Procedures Committee examines each proposed rule for the purpose of determining whether the rule reiterates or paraphrases statutory material. Staff believes that Rule 25-6.093, F.A.C., reiterates paragraph 366.05(1)(d), F.S., on information regarding available rates and assistance in selecting the most advantageous rate. Therefore, staff recommends that the specific provisions of Rule 25-6.093, F.A.C., which reiterate paragraph 366.05(1)(d), F.S. be deleted.

Staff is also recommending that the Commission propose amendments to sections (1), (2), and (4) of the rule to remove obsolete rule language and to clarify the rule.

Rule 25-6.097, F.A.C.

Rule 25-6.097, F.A.C., Customer Deposits, provides that each company's tariff shall contain the specific criteria for determining the amount of initial deposit. This rule states that for new or additional deposits, the total amount of the deposit shall not exceed an amount equal to twice the average charges for actual usage of electric service for the twelve month period immediately prior to the date of notice.

Staff recommends amendments to Rule 25-6.097, F.A.C., stating that the methodology shall conform to paragraph 366.05(1)(c), F.S. The specific reference to paragraph 366.05(1)(c), F.S., clarifies that utilities must adhere to the statutory methodology for calculating the amount of the deposit.

Staff is also recommending that the Commission propose amendment to section (1) of the rule to move the requirements for the establishment of credit to section (2) of the rule. Staff believes that this amendment will make the rule clearer. Staff is also recommending amendments to sections (4), (6) and (7) of the rule to remove obsolete rule language and to clarify the rule provisions.

Rule 25-6.100, F.A.C.

Rule 25-6.100, F.A.C., Customer Billings, prescribes the information that electric utilities must provide to customers when rendering a bill. This information must be provided with the dollar amount of the bill, the customer charge, total electric cost, taxes, and past due balances.

Staff recommends amended language stating that the dollar amount of the bill must include the rate and amount of the "Asset Securitization Charge" as a separate line item pursuant to paragraph 366.95(4)(b), F.S., if applicable. This language reflects the requirements of paragraph 366.95(4)(b), F.S., that this charge be identified as a separate line item on the customer's bill.

TECO submitted comments and represented that FPL and Duke Energy concurred with TECO's comments. TECO suggested that Rule 25-6.100(2)(c)5., F.A.C., should state that the total electric cost reflected on the customer's bill, should be at a minimum, the costs identified in Rule 25-6.100(2)(c)1.-4., F.A.C., but can include other line item charges, e.g., Asset Securitization Charge, Florida Gross Receipts Tax, etc. TECO asserted that the suggested language simplifies the description of what is included in the total electric cost, and provides flexibility for the utilities to include other line items as they exist now or may be developed and implemented in the future.

Staff does not recommend that this language suggested by TECO, FPL, and Duke be included in Rule 25-6.100(2)(c)5., F.A.C. Paragraph 366.95(4)(b), F.S., is prescriptive and requires that electric utilities state the Asset Securitization Charge as a separate line item on the customer's bill. Language suggested by TECO, FPL and Duke that the customer's bill can include the Asset

Securitization Charge does not conform to the statutory requirement that the bill must explicitly identify this charge if applicable. Staff recommends that subparagraph 25-6.100(2)(c)11., F.A.C., be added to the rule stating that the rate and amount of the "Asset Securitization Charge" pursuant to paragraph 366.95(4)(b), F.S., if applicable, must be itemized on the customer's bill.

FPL suggested that Rule 25-6.100(4), F.A.C., be amended to state that the advancement or postponement of the regular meter reading date is governed by subsection 366.05(1)(b), F.S. FPL stated that FPL employees routinely refer to the rule with customers as authority when addressing any issue involving the advancement or postponement of the regular meter reading date. FPL states that this suggested revision of the rule will provide an adequate reference point to the Florida Statutes when communications take place between FPL and its customers.

TECO made a similar suggestion that Rule 25-6.100(4), F.A.C., should contain new language citing subsection 366.05(1)(b), F.S., so that utilities will be on notice that advancement or postponement of regular meter reading dates is addressed by reference to the statute, and not the rule. Staff recommends amendments to the provisions of Rule 25-6.100(4), F.A.C., regarding the advancement or postponement of the regular meter reading date as suggested by FPL, TECO, and Duke.

OPC commented that the reference in Rule 25-6.100, F.A.C., to the utility's "local business office" should be amended to state contacting the utility. Staff recommends this amendment because many utilities no longer have numerous local business offices.

Gas Utilities

Rule 25-7.079, F.A.C.

Rule 25-7.079, F.A.C., Information to Customers, states that each utility shall, upon request, give its customers such information and assistance as is reasonable, in order that the customer may secure safe and efficient service. The rule also states that it is the duty of the utility to assist the customer in obtaining the rate which is most advantageous for the customer's service requirements.

Paragraph 366.05(1)(d), F.S., states that if a utility has more than one rate for any customer class, it must notify each customer in that class of available rates and explain how the rate is charged to the customer. The statute states that if a customer contacts the utility seeking assistance in selecting the most advantageous rate, the utility must provide good faith assistance to the customer.

Staff believes that Rule 25-7.079, F.A.C., reiterates the provisions of paragraph 366.05(1)(d), F.S., regarding customer information and the obtainment of the most advantageous rate for the customer's service requirements. Pursuant to paragraph 120.545(1)(c), F.S., the Joint Administrative Procedures Committee examines each proposed rule for the purpose of determining whether the rule reiterates or paraphrases statutory material. Staff believes that Rule 25-7.079, F.A.C., reiterates paragraph 366.05(1)(d), F.S., on information regarding available rates and assistance in selecting the most advantageous rate. Therefore, staff recommends that the specific provisions of Rule 25-7.079, F.A.C., which reiterate paragraph 366.05(1)(d), F.S. be deleted.

Rule 25-7.083, F.A.C.

Rule 25-7.083, F.A.C., Customer Deposits, states that each company's tariff shall contain specific criteria for determining the amount of initial deposit. Paragraph 366.05(1)(c), F.S., contains specific methodologies for the calculation of deposits by utilities for existing accounts and new service requests.

Staff recommends amendments to Rule 25-7.083, F.A.C., to conform the rule to subparagraphs 366.05(1)(c)1.and 2., F.S. Staff recommends language stating that each company's tariff shall identify the methodology for determining the amount of the deposit charged for existing accounts and new service requests. Staff recommends that the rule contain language similar to that in Rule 25-6.097, F.A.C., i.e., that the methodology shall conform to paragraph 366.05(1)(c), F.S. This reference to paragraph 366.05(1)(c), F.S., identifies the formulas for the calculation of deposits by gas utilities.

Rule 25-7.085, F.A.C.

Rule 25-7.085, F.A.C., Customer Billing, specifies the procedures that gas utilities must follow when billing customers for service. Rule 25-7.085(5), F.A.C, states that regular meter reading dates may be advanced or postponed not more than five days without a proration of the billing for the period.

Subsection 366.05(1)(b), F.S., provides that regular meter reading dates may not be advanced or postponed more than 5 days for routine operating reasons without prorating the bill. Staff recommends the deletion of this provision in Rule 25-7.085, F.S., because it reiterates subsection 366.05(1)(b), F.S.

Peoples suggested that Rule 25-7.085(5), F.A.C., be amended to provide a reference to subsection 366.05(1)(b), F.S., regarding the advancement or postponement of the regular meter reading date. Peoples suggests this language because billing employees at the utility utilize the Florida Administrative Code rather than the Florida Statutes to respond to billing questions that arise. Staff recommends the language suggested by Peoples that puts gas utilities on notice that the advancement or postponement of the regular meter reading date is addressed in the statute.

OPC commented that the reference to "local office" is no longer suitable because most gas utilities do not currently have numerous local offices. Peoples made similar comments as to the use of the term "local office." Staff agrees with the comments and recommends amending this language to state "utility."

OPC suggested that the term "utility" be substituted for the word "company" in Rule 25-7.085, F.A.C.[1] Staff recommends this amendment to so that the references to gas utilities use terminology that is consistent with the terms used in rules applicable to electric utilities.

Statement of Estimated Regulatory Costs

[1] OPC made this suggestion in comments on Rules 25-6.097, 25-6.100, and 25-7.083, F.A.C. Staff also recommends amendments to Rules 25-6.097, 25-6.100, and 25-7.083, F.A.C., substituting "company" with "utility."

Pursuant to Section 120.54, F.S., agencies are encouraged to prepare a statement of estimated regulatory costs (SERC) before the adoption, amendment, or repeal of any rule. The SERC is appended as Attachment B to this recommendation. The SERC analysis includes whether the rule amendment is likely to have an adverse impact on growth, private sector job creation or employment, or private sector investment in excess of $1 million in the aggregate within five years after implementation.[2]

The SERC concludes that the rule amendments will not likely directly or indirectly increase regulatory costs in excess of $200,000 in the aggregate in Florida within one year after implementation. The SERC states that any economic impacts that might be incurred by affected entities would be a result of statutory changes promulgated under Sections 366.05 and 366.95, F.S., and not caused by staff's recommended changes to Commission rules. The SERC states that several comments from interested parties were incorporated into the draft rules to provide additional clarification. No regulatory alternatives were submitted pursuant to paragraph 120.541(1)(a), F.S. The SERC concludes that because the estimated additional transactional costs are caused by statutory changes to Commission rules, none of the impact/cost criteria established in paragraph 120.541(2)(a), F.S., will be exceeded as a result of the recommended revisions.

Conclusion

Based on the foregoing, staff recommends the amendment of Rules 25-6.093, 25-6.097, 25-6.100, 25-7.079, 25-7.083, and 25-7.085, F.A.C.

[2] Section 120.541(2), F.S.

Issue 2: Should this docket be closed?

Recommendation: Yes. If no requests for hearing or comments are filed, the rules may be filed with the Department of State, and this docket should be closed. (Page)

Staff Analysis: If no requests for hearing or comments are filed, the rules may be filed with the Department of State, and this docket should be closed.

25-6.093 Information to Customers.

(1) ~~Each utility shall, upon request of any customer, give such information and assistance as is reasonable, in order that the customer may secure safe and efficient service.~~ Upon the customer's request, the utility shall provide to the ~~any~~ customer information as to the method of reading meters and the derivation of billing therefrom, the billing cycle and approximate date of monthly meter reading.

(2) Upon request of the ~~any~~ customer, the utility shall ~~is required to~~ provide to the customer a copy and explanation of the utility's rates and provisions applicable to the type or types of service furnished or to be furnished such customer~~, and to assist the customer in obtaining the rate schedule which is most advantageous to the customer's requirements~~.

(3)(a) By paper or electronic bill insert, billing statement, website, electronic notification, or other means agreed to by both the customer and the utility ~~appropriate means of communication~~, the utility shall give to each of its customers a summary of all available electrical ~~major~~ rates ~~schedules~~ that ~~which~~ are available to the class of which that customer is a member.~~, and~~

(b) The utility shall provide the information contained in paragraph (a) to all its customers:

1. Not later than 60 days after the commencement of service, ~~and~~

2. Not less frequently than once each year, and

3. Not later than 60 days after the utility has received approval of its new rate schedule applicable to such customer.

(c) In this subsection, "rate schedule" shall mean customer charge, energy charge, and demand charge, as set forth in Rule 25-6.100, F.A.C.

(d) By bill insert, or as a message on the customer bill, on a quarterly basis using the utility's normal billing cycle, each utility shall provide its customers the sources of generation for the most recent 12-month period available prior to the billing cycle. The sources of generation

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shall be stated by fuel type for utility generation and as "purchased power" for off-system purchases. The sources of generation are to be set forth as kilowatt-hour percentages of the total utility generation and purchased power.

(4) Upon request of <u>the</u> ~~any~~ customer, but not more frequently than once each calendar year, the utility shall <u>provide to the customer</u> ~~transmit~~ a concise statement of the actual consumption of electric energy by that customer for each billing period during the previous 12 months.

Rulemaking Authority 366.05(1), 350.127(2) FS. Law Implemented 366.03, 366.04(2)(f), (6), 366.041(1), 366.05(1), (3), 366.06(1) FS. History–New 7-29-69, Amended 11-26-80, 6-28-82, 10-15-84, Formerly 25-6.93, Amended 4-18-99,__________.

25-6.097 Customer Deposits.

(1) ~~Deposit required; establishment of credit.~~ Each utility's ~~company's~~ tariff shall state the methodology ~~contain their specific criteria~~ for determining the amount of the ~~initial~~ deposit charged for existing accounts and new service requests. The methodology shall conform to paragraph 366.05(1)(c), F.S. ~~Each utility may require an applicant for service to satisfactorily establish credit, but such establishment of credit shall not relieve the customer from complying with the utilities' rules for prompt payment of bills. Credit will be deemed so established if:~~

~~(a) The applicant for service furnishes a satisfactory guarantor to secure payment of bills for the service requested. For residential customers, a satisfactory guarantor shall, at the minimum, be a customer of the utility with a satisfactory payment record. For non-residential customers, a satisfactory guarantor need not be a customer of the utility. Each utility shall develop minimum financial criteria that a proposed guarantor must meet to qualify as a satisfactory guarantor. A copy of the criteria shall be made available to each new non-residential customer upon request by the customer. A guarantor's liability shall be terminated when a residential customer whose payment of bills is secured by the guarantor meets the requirements of subsection (2) of this rule. Guarantors providing security for payment of residential customers' bills shall only be liable for bills contracted at the service address contained in the contract of guaranty.~~

~~(b) The applicant pays a cash deposit.~~

~~(c) The applicant for service furnishes an irrevocable letter of credit from a bank or a surety bond.~~

(2) Each utility may require an applicant for service to satisfactorily establish credit, but such establishment of credit shall not relieve the customer from complying with the utility's rules for payment of bills. Credit will be deemed so established if:

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(a) The applicant for service furnishes a satisfactory guarantor to secure payment of bills for the service requested. For residential customers, a satisfactory guarantor shall, at the minimum, be a customer of the utility with a satisfactory payment record. For non-residential customers, a satisfactory guarantor need not be a customer of the utility. Each utility shall develop minimum financial criteria that a proposed guarantor must meet to qualify as a satisfactory guarantor. A copy of the criteria shall be made available to each new non-residential customer upon request by the customer. A guarantor's liability shall be terminated when a residential customer whose payment of bills is secured by the guarantor meets the requirements of subsection (3) of this rule. Guarantors providing security for payment of residential customers' bills shall only be liable for bills contracted at the service address contained in the contract of guaranty.

(b) The applicant pays a cash deposit.

(c) The applicant for service furnishes an irrevocable letter of credit from a bank or a surety bond.

(3~~2~~) Refund of deposits. After a customer has established a satisfactory payment record and has had continuous service for a period of 23 months, the utility shall refund the residential customer's deposits and shall, at the utility's ~~its~~ option, either refund or pay the higher rate of interest specified below for nonresidential deposits, providing the customer has not, in the preceding 12 months:~~.~~

(a) Made more than one late payment of a bill (after the expiration of 20 days from the date of mailing or delivery by the utility).

(b) Paid with a check refused by a bank.

(c) Been disconnected for nonpayment, or at any time.

(d) Tampered with the electric meter, or

(e) Used service in a fraudulent or unauthorized manner.

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(4~~3~~) Deposits for existing accounts ~~New or additional deposits.~~ A utility may charge ~~require~~, upon ~~reasonable~~ written notice to the customer of not less than thirty (30) days, a ~~new deposit, where previously waived or returned, or additional~~ deposit on an existing account~~,~~ in order to secure payment of ~~current~~ bills. Such request for a deposit shall be separate and apart from any bill for service and shall explain the reason for the ~~such new or additional~~ deposit~~, provided, however, that the total amount of the required deposit shall not exceed an amount equal to twice the average charges for actual usage of electric service for the twelve month period immediately prior to the date of notice. In the event the customer has had service less than twelve months, then the utility shall base its new or additional deposit upon the average actual monthly usage available~~. The deposit charged must conform to the requirements of Section 366.05(1)(c)1., F.S.

(5~~4~~) Interest on deposits.

(a) Each electric utility which requires deposits to be made by its customers shall pay a minimum interest on such deposits of 2 percent per annum. The utility shall pay an interest rate of 3 percent per annum on deposits of nonresidential customers qualifying under subsection (3~~2~~) when the utility elects not to refund such deposit after 23 months. ~~Such interest rates shall be applied within 45 days of the effective date of the rule.~~

(b) The deposit interest shall be simple interest in all cases and settlement shall be made annually, either in cash or by credit on the current bill. This does not prohibit any utility paying a higher rate of interest than required by this rule. No customer depositor shall be entitled to receive interest on a ~~his~~ deposit until and unless a customer relationship and the deposit have been in existence for a continuous period of six months, then the customer ~~he~~ shall be entitled to receive interest from the day of the commencement of the customer relationship and the placement of deposit. Nothing in this rule shall prohibit a utility from refunding at any time a deposit with any accrued interest.

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(6~~5~~) Record of deposits. Each utility ~~having on hand deposits from a customer or hereafter receiving deposits from them~~ shall keep records to show:

(a) The name of each customer making the deposit;

(b) The premises for which the deposit applies ~~occupied by the customer~~;

(c) The date and amount of deposit; and

(d) Each transaction concerning the deposits such as interest payments, interest credited or similar transactions.

(7~~6~~) Receipt for deposit. The utility shall provide a receipt to the customer for any deposit received from the customer ~~A non-transferable certificate of deposit shall be issued to each customer and means provided so that the customer may claim the deposit if the certificate is lost. Where a new or additional deposit is required under subsection (3) of this rule, a customer's cancelled check or validated bill coupon may serve as a deposit receipt~~.

(8~~7~~) Refund of deposit when service is discontinued. Upon termination of service, the deposit and accrued interest may be credited against the final account and the balance, if any, shall be returned promptly to the customer but in no event later than fifteen (15) days after service is discontinued.

Rulemaking Authority 366.05(1), 350.127(2) FS. Law Implemented 366.03, 366.041(1), 366.05(1), 366.06(1) FS. History–New 7-29-69, Amended 5-9-76, 7-8-79, 6-10-80, 10-17-83, 1-31-84, Formerly 25-6.97, Amended 10-13-88, 4-25-94, 3-14-99, 7-26-12, ___________.

CODING: Words underlined are additions; words in ~~struck through~~ type are deletions from existing law.

25-6.100 Customer Billings.

(1) Bills shall be rendered monthly and as promptly as possible following the reading of meters.

(2) ~~By January 1, 1983,~~ Eeach customer's bill shall show at least the following information:

(a) The meter reading and the date the meter is read, in addition to the meter reading for the previous period. If the meter reading is estimated, the word "estimated" shall be prominently displayed on the bill.

(b)1. Kilowatt-hours (KWH) consumed including on and off peak if customer is time-of-day metered.

2. Kilowatt (KW) demand, if applicable, including on and off peak if customer is time-of-day metered.

(c) The dollar amount of the bill, including separately:

1. Customer, Base or Basic Service charge.

2. Energy (KWH) charges, exclusive of fuel, in cents per KWH~~, including amounts for on and off peak if the customer is time-of-day metered,~~ and applicable cost recovery clause charges ~~energy conservation costs~~.

3. Demand (KW) charges, exclusive of fuel, in dollar cost per KW, if applicable, for any demand charges included in the utility's rate structure and applicable cost recovery clause charges ~~including amounts for on and off peak if the customer is time-of-day metered~~.

4. Fuel (KWH) charges ~~cost~~ in cents per KWH (no fuel costs shall be included in the Energy or Demand ~~base~~ charges~~ for demand or energy)~~.

5. Total electric cost which, at a minimum, is the sum of ~~the customer charge, total fuel cost, total energy cost, and total demand cost.~~ charges 1 through 4 above but can include other line item charges (e.g., Florida Gross Receipts Tax, etc.).

6. Franchise fees, if applicable.

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7. Taxes, as applicable on purchases of electricity by the customer.

8. Any discount or penalty, if applicable.

9. Past due balances shown separately.

10. The gross and net billing, if applicable.

11. The rate and amount of the "Asset Securitization Charge," pursuant to paragraph 366.95(4)(b), F.S., if applicable.

(d) Identification of the applicable rate schedule.

(e) The date by which payment must be made in order to benefit from any discount or avoid any penalty, if applicable.

(f) The average daily KWH consumption for the current period and for the same period in the previous year, for the same customer at the same location.

(g) The delinquent date or the date after which the bill becomes past due.

(h) Any conversion factors which can be used by customers to convert from meter reading units to billing units. Where metering complexity makes this requirement impractical, a statement must be on the bill advising where and how ~~that~~ such information may be obtained from ~~by contacting~~ the utility~~'s local business office~~.

(i) Where budget billing is used, ~~the bill shall contain~~ the current month's actual consumption and charges should be shown separately from budgeted amounts.

(j) If applicable, the information required by subsection 366.8260(4), F.S., and subsection 366.95(4), F.S.

(k~~j~~) The name and address of the utility and ~~plus~~ the telephone ~~toll-free~~ number(s) and web address where customers can receive information about their bill as well as locations where the customers can pay their utility bill. Such information must identify those locations where no surcharge is incurred.

(3) When there is sufficient cause, estimated bills may be submitted provided that with the

third consecutive estimated bill the company shall contact the customer explaining the reason for the estimated billing and who to contact in order to obtain an actual meter reading. An actual meter reading must be taken at least once every six months. If an estimated bill appears to be abnormal when a subsequent reading is obtained, the bill for the entire period shall be computed at a rate which contemplates the use of service during the entire period and the estimated bill shall be deducted. If there is reasonable evidence that such use occurred during only one billing period, the bill shall be computed.

(4) The advancement or postponement of t~~T~~he regular meter reading date is governed by subsection 366.05(1)(b), F.S. ~~may be advanced or postponed not more than five days without a pro-ration of the billing for the period.~~

(5) Whenever the period of service for which an initial or opening bill is rendered is less than the normal billing period, the charges applicable to such service, including minimum charges, shall be prorated ~~pro-rated~~ except that initial or opening bills need not be rendered but the energy used during such period may be carried over to and included in the next regular monthly billing.

(6) The practices employed by each utility regarding customer billing shall have uniform application to all customers on the same rate schedule.

(7) Franchise Fees.

(a) When a municipality charges a utility any franchise fee, the utility may collect that fee only from its customers receiving service within that municipality. When a county charges a utility any franchise fee, the utility may collect that fee only from its customers receiving service within that county.

(b) A utility may not incorporate any franchise fee into its other rates for service.

(c) For the purposes of this subsection, the term "utility" shall mean any electric utility, rural electric cooperative, or municipal electric utility.

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(d) This subsection shall not be construed as granting a municipality or county the authority to charge a franchise fee. This subsection only specifies the method of collection of a franchise fee, if a municipality or county, having authority to do so, charges a franchise fee.

Rulemaking Authority 366.05(1), 366.04(2) FS. Law Implemented 366.03, 366.04(2), 366.041(1), 366.05(1), 366.051, 366.06(1), 366.8260(4), 366.95(4) FS. History–New 2-25-76, Amended 4-13-80, 12-29-81, 6-28-82, 5-16-83, 2-4-13,__________.

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25-7.079 Information to Customers.

(1) ~~Each utility shall, upon request, give its customers such information and assistance as is reasonable, in order that the customer may secure safe and efficient service.~~ The utility shall, when requested~~,~~ by the customer, provide to the ~~any~~ customer information as to the method of reading meters and derivation of billing therefrom.

(2) Upon request of the ~~any~~ customer, ~~it shall be the duty of~~ the utility shall ~~to~~ provide to the customer~~,~~ a copy and/or explanation of the utility's rates applicable to the type or types of service furnished or to be furnished to the ~~such~~ customer~~, and to assist him in obtaining the rate which is most advantageous for the customer's his service requirements~~.

Rulemaking Authority 366.05(1) FS. Law Implemented 366.03, 366.05(1), 366.06 FS. History–New 1-8-75, Repromulgated 5-4-75, Formerly 25-7.79, Amended ___________.

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25-7.083 Customer Deposits

(1) ~~Deposit required; establishment of credit.~~ Each utility's ~~company's~~ tariff shall state the methodology ~~contain their specific criteria~~ for determining the amount of the ~~initial~~ deposit charged for existing accounts and new service requests. The methodology shall conform to Section 366.05(1)(c), F.S. ~~Each utility may require an applicant for service to satisfactorily establish credit, but such establishment of credit shall not relieve the customer from complying with the utilities' rules for prompt payment of bills. Credit will be deemed so established if:~~

~~(a) The applicant for service furnishes a satisfactory guarantor to secure payment of bills for the service requested. For residential customers, a satisfactory guarantor shall, at the minimum, be a customer of the utility with a satisfactory payment record. For non-residential customers, a satisfactory guarantor need not be a customer of the utility. Each utility shall develop minimum financial criteria that a proposed guarantor must meet to qualify as a satisfactory guarantor. A copy of the criteria shall be made available to each new non-residential customer upon request by the customer. A guarantor's liability shall be terminated when a residential customer whose payment of bills is secured by the guarantor meets the requirements of subsection (6) of this rule. Guarantors providing security for payment of residential customers' bills shall only be liable for bills contracted at the service address contained in the contract of guaranty.~~

~~(b) The applicant pays a cash deposit.~~

~~(c) The applicant for service furnishes an irrevocable letter of credit from a bank or a surety bond.~~

(2) Each utility may require an applicant for service to satisfactorily establish credit, but such establishment of credit shall not relieve the customer from complying with the utility's rules for payment of bills. Credit will be deemed so established if:

(a) The applicant for service furnishes a satisfactory guarantor to secure payment of bills for the service requested. For residential customers, a satisfactory guarantor shall, at the minimum, be a customer of the utility with a satisfactory payment record. For non-residential customers, a satisfactory guarantor need not be a customer of the utility. Each utility shall develop minimum financial criteria that a proposed guarantor must meet to qualify as a satisfactory guarantor. A copy of the criteria shall be made available to each new non-residential customer upon request by the customer. A guarantor's liability shall be terminated when a residential customer whose payment of bills is secured by the guarantor meets the requirements of subsection (7) of this rule. Guarantors providing security for payment of residential customers' bills shall only be liable for bills contracted at the service address contained in the contract of guaranty.

(b) The applicant pays a cash deposit.

(c) The applicant for service furnishes an irrevocable letter of credit from a bank or a surety bond.

(3~~2~~) Receipt for deposit. The utility shall provide a receipt to the customer for any deposit received from the customer. ~~A non-transferable certificate of deposit shall be issued to each customer and means provided so that the customer may claim the deposit if the certificate is lost. When a new or additional deposit is required under subsection (3) of this rule a customer's cancelled check or validated bill coupon may serve as a deposit receipt.~~

(4~~3~~) Deposits for existing accounts ~~New or additional deposits~~. A utility may charge ~~require~~, upon ~~reasonable~~ written notice to the customer of not less than 30 days, ~~such request or notice being separate and apart from any bill for service, a new deposit, where previously waived or returned, or an additional~~ a deposit on an existing account~~,~~ in order to secure payment of ~~current~~ bills~~; provided, however, that the total amount of the required deposit shall not exceed an amount equal to the average actual charges for gas service for two billing periods for the~~

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~~12-month period immediately prior to the date of notice. In the event the customer has had service less than 12 months, then the utility shall base its new or additional deposit upon the average actual monthly billing available~~. Such request for a deposit shall be separate and apart from any bill for service and shall explain the reason for the deposit. The deposit charged must conform to the requirements of Section 366.05(1)(c)1., F.S.

(5~~4~~) Record of deposit. Each utility ~~having on hand deposits from customers or hereafter receiving deposits from them~~ shall keep records to show:

(a) The name of each customer making the deposit;

(b) The premises for which the deposit applies ~~occupied by the customer~~;

(c) The date and amount of deposit; and

(d) Each transaction concerning the deposit such as interest payments, interest credited or similar transactions.

(6~~5~~) Interest on deposits.

(a) Each gas utility which requests deposits to be made by its customers shall pay a minimum interest on such deposits of 2 percent per annum. The utility shall pay a minimum interest rate of 3 percent per annum on deposits of nonresidential customers qualifying under subsection (7~~6~~) below when the utility elects not to refund such a deposit after 23 months. ~~Such interest rates shall be applied within 45 days of the effective date of the rule.~~

(b) The deposit interest shall be simple interest in all cases and settlement shall be made annually, either in cash or by credit on the current bill. This does not prohibit any utility paying a higher rate of interest than required by this rule. No customer depositor shall be entitled to receive interest on a ~~his~~ deposit until and unless a customer relationship and the deposit have been in existence for a continuous period of six months, then the customer ~~he~~ shall be entitled to receive interest from the day of the commencement of the customer relationship and the placement of deposit. Nothing in this rule shall prohibit a utility from

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refunding at any time a deposit with any accrued interest.

(7~~6~~) Refund of deposit. After a customer has established a satisfactory payment record and has had continuous service for a period of 23 months, the utility shall refund the residential customer's deposits and shall, at the utility's ~~its~~ option, either refund or pay the higher rate of interest specified above for nonresidential deposits, provided the customer has not, in the preceding 12 months:

(a) Made more than one late payment of a bill (after the expiration of 20 days from the date of mailing or delivery by the utility);

(b) Paid with check refused by a bank;

(c) Been disconnected for nonpayment, or at any time;

(d) Tampered with the gas meter; or

(e) Used service in a fraudulent or unauthorized manner. ~~Nothing in this rule shall prohibit the company from refunding at any time a deposit with any accrued interest.~~

(8~~7~~) Refund of deposit when service is disconnected. Upon termination of service, the deposit and accrued interest may be credited against the final account and the balance, if any, shall be returned promptly to the customer but in no event later than fifteen (15) days after service is discontinued.

Rulemaking Authority 366.05(1), 350.127(2) FS. Law Implemented 366.03, 366.05(1) FS. History–New 1-8-75, Amended 6-15-76, 6-10-80, 1-31-84, Formerly 25-7.83, Amended 10-13-88, 4-25-94, 3-14-99, 7-26-12,_____________.

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25-7.085 Customer Billing.

(1) Bills shall be rendered monthly. With the exception of a duplicate bill, each customer's bill shall show at least the following information:

(a) The meter reading and the date the meter was read plus the meter reading for the previous period. When an electronic meter is used, the gas volume consumed for the billing month may be shown. If the gas consumption is estimated, the word "estimated" shall prominently appear on the bill.

(b) Therms and cubic feet consumed.

(c) The total dollar amount of the bill, indicating separately:

1. Customer, Base or Basic Service charge.

2. Energy (therm) charges exclusive of fuel cost in cents per therm.

3. Fuel (therm) charges ~~cost~~ in cents per therm (no fuel costs shall be included in the charge for energy).

4. Total gas cost which at a minimum is the sum of charges 1 through 3 above but can include other line item charges (e.g., Florida Gross Receipts Tax) ~~the customer charge, total fuel cost and total energy cost~~.

5. Franchise fees, if applicable.

6. Taxes, as applicable on purchases of gas by the customer.

7. Any discount or penalty, if applicable.

8. Past due balances.

9. The gross and net billing, if applicable.

(d) Identification of the applicable rate schedule.

(e) The date by which payment must be made in order to benefit from any discount or avoid any penalty, if applicable.

(f) The average daily therm consumption for the current period and for the same period in the

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previous year, for the same customer at the same location.

(g) The delinquent date or the date after which the bill becomes past due.

(h) Any conversion factors which can be used by customers to convert from meter reading units to billing units.

(i) Where budget billing is used, the bill shall contain the current month's consumption and charges separately from budgeted amounts.

(j) The name of the utility plus the address, ~~and~~ telephone number(s) and web address ~~of the local office~~ where the bill can be paid and questions concerning the bill can be answered.

(2) All gas utilities shall charge for gas service on a thermal basis instead of on a volume basis. The provisions governing customer billing on a thermal basis shall be as follows:

(a) The unit of service shall be the "Therm."

(b) The number of therms which shall have been taken by consumer during a given period shall be determined by multiplying the difference in the meter readings in cubic feet at the beginning and end of the period by the conversion factors in paragraph (1)(h) including a heating-value factor which has been determined as prescribed in paragraph (c) below.

(c) The heating-value factor for gas utilities receiving and distributing natural gas shall be the average thermal value of the natural gas received and distributed during the preceding month. In case the average heating value during the calendar month has been below the standard, then the value to be used in determining the factor shall be the heating value standard minus a deduction of one percent (1%) for each one percent (1%) or fraction thereof that the average heating value has been below the standard.

(d) The consumer shall be billed to the nearest one-tenth of a therm.

(3) Whenever the period of service for which an initial or opening bill would be rendered is less than the normal billing period, no bill for that period need be rendered if the volume amount consumed is carried over and included in the next regular monthly billing. If,

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however, a bill for such period is rendered, the applicable charges, including minimum charges, shall be prorated.

(4) When there is sufficient cause, estimated billings may be used by a utility provided that with the customer's third consecutive estimated billing the customer is informed of the reason for the estimation and whom to contact to obtain an actual meter reading if one is desired. An actual meter reading must be taken at least once every six months. If an estimated bill appears to be abnormal once an actual meter reading is obtained, the bill for the entire estimation period shall be computed at a rate based on use of service during the entire period and the estimated bill shall be deducted. If there is substantial evidence that such use occurred during only one billing period, the bill shall be computed.

(5) The advancement or postponement of r~~R~~egular meter reading dates is governed by subsection 366.05(1)(b), F.S. ~~may be advanced or postponed not more than five days without a proration of the billing for the period.~~

(6) The practices employed by each utility regarding customer billing shall have uniform application to all customers on the same rate schedule.

(7) Franchise Fees.

(a) When a municipality charges a utility any franchise fee, the utility may collect that fee only from its customers receiving service within that municipality. When a county charges a utility any franchise fee, the county may collect that fee only from its customers receiving service within that county.

(b) A utility ~~company~~ may not incorporate any franchise fee into its other rates for service.

(c) This subsection shall not be construed as granting a municipality or county the authority to charge a franchise fee. This subsection only specifies the method of collection of a franchise fee, if a municipality or county, having authority to do so, charges a franchise fee.

Rulemaking Authority 366.05(1) FS. Law Implemented 366.05(1), 366.06(1) FS. History–New

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12-15-73, Repromulgated 1-8-75, Amended 5-4-75, 11-21-82, 12-26-82, Formerly 25-7.85, Amended 10-10-95, 7-3-96, ______________.

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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: November 6, 2015

TO: Pamela H. Page, Senior Attorney, Office of the General Counsel

FROM: Clyde D. Rome, Public Utility Analyst II. Division of Economics CDR

RE: Statement of Estimated Regulatory Costs for Recommended Revisions to Chapters 25-6 (Electric Service by Electric Public Utilities) and 25-7 (Gas Service by Gas Public Utilities), Florida Administrative Code (F.A.C.)

During the 2015 session, the Florida Legislature enacted House Bill 7109 which was incorporated into Chapter 2015-129, Laws of Florida. Among other things, the legislation added new requirements to Section 366.05, Florida Statutes (F.S.) and created Section 366.95, F.S. These laws became effective on July 1, 2015. To implement the new laws, staff is recommending amendments to Rules 25-6.093 and 25-7.079, F.A.C. (Information to Customers), Rules 25-6.097 and 25-7.083, F.A.C. (Customer Deposits), and Rules 25-6.100 and 25-7.085, F.A.C. (Customer Billings). Staff is recommending these rule changes so that Commission rules will continue to be consistent with the requirements of the empowering statutes as revised during the 2015 legislative session. Therefore, any economic impacts that might be incurred by affected entities would be a result of statutory changes promulgated under Sections 366.05 and 366.95, F.S., and not caused by staff's recommended changes to Commission rules.

The attached Statement of Estimated Regulatory Costs (SERC) addresses the considerations required pursuant to Section 120.541, Florida Statutes (F.S.). The SERC contains an appendix which is divided into two sections. Section 1 of the SERC Appendix includes a summary of the key rule changes. Section 2 contains a discussion of the prospective rule amendments associated with statutory changes that potentially may result in additional transactional costs.

Benefits of the statutory changes and the recommended rule revisions to implement the statutory changes potentially may be realized by investor-owned electric and gas utilities and their ratepayers. Utilities may experience fewer customer complaints regarding charges billed or other customer service issues. Ratepayers of electric utilities with nuclear asset-recovery bonds potentially may benefit from having the asset securitization charge listed as a separate line item on customer bills as it may lead to better customer understanding of the charges for which they are billed. Electric and gas utility ratepayers potentially may benefit from additional utility assistance in selecting the appropriate rate schedule to best meet their specific needs and from the clarification of the method of determining customer deposits. Electric and gas utility ratepayers also may benefit in the form of lower bills due to the prohibition of charging for usage at a higher tiered rate if the usage increase is attributable to an extension in the billing period.

No workshop was requested in conjunction with the recommended rule revisions. Several comments from interested parties were incorporated into the draft rules to provide additional clarification. No regulatory alternatives were submitted pursuant to paragraph 120.541(1)(a), F.S. Because the estimated additional transactional costs are caused by statutory changes and not staff's recommended changes to Commission rules, none of the rule impact/cost criteria established in paragraph 120.541(2)(a), F.S., will be exceeded as a result of the recommended revisions.

cc: (Draper, Daniel, Shafer, Cibula, SERC file)

Florida Public Service Commission
Statement of Estimated Regulatory Costs
Chapters 25-6 and 25-7, F.A.C.

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

   Yes ☐ No ☒

For clarification, please see comments in Sections A(3) and E(1), below.

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

   Yes ☐ No ☒

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

A. Whether the rule directly or indirectly:

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

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

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

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

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

Yes ☐ No ☒

Economic Analysis:
A summary of the key rule changes is included in Section 1 of the SERC Appendix. Specific elements of the associated economic analysis are identified below in Sections B through F of this SERC.

During the 2015 session, the Florida Legislature enacted House Bill 7109 which was incorporated into Chapter 2015-129, Laws of Florida. Among other things, the legislation added new requirements to Section 366.05, F.S., and created Section 366.95, F.S. These laws became effective on July 1, 2015. To implement the new laws, staff is recommending amendments to Rules 25-6.093 and 25-7.079, F.A.C. (Information to Customers), Rules 25-6.097 and 25-7.083, F.A.C. (Customer Deposits), and Rules 25-6.100 and 25-7.085, F.A.C. (Customer Billings). Staff is recommending these rule changes so that Commission rules will continue to be consistent with the requirements of the empowering statutes as revised during the 2015 legislative session.

Therefore, any economic impacts that might be incurred by affected entities would be a result of statutory changes promulgated under Sections 366.05 and 366.95, F.S., and not caused by staff's recommended changes to Commission rules. Because estimated additional transactional costs are caused by statutory changes and not staff's recommended changes to Commission rules, none of the rule impact/cost criteria established in paragraph 120.541(2)(a), F.S., will be exceeded as a result of the recommended rule revisions.

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

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

Potentially affected entities include 5 investor-owned electric utilities and 8 investor-owned natural gas utilities. Utilities which come under the jurisdiction of the Commission in the future also would be required to comply.

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

Florida's 5 investor-owned electric utilities serve approximately 7.45 million customers. Florida's 8 investor-owned natural gas utilities serve approximately 530,000 customers.

[Source: Facts and Figures of the Florida Utility Industry; PSC - March 2015]

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

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

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

☐ Minimal. Provide a brief explanation.

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

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

☒ None. The rule will only affect the Commission.

☐ Minimal. Provide a brief explanation.

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

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

☐ None.

☐ Minimal. Provide a brief explanation.

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

It is not anticipated that state and local governments would incur additional costs in association with the recommended rule revisions. Staff notes that the final bill analysis prepared in support of HB 7109 indicated that the Revenue Estimating Conference projected a negative fiscal impact on state revenues of $400,000 in FY 2015-2016 and a recurring $1.6 million in FY 2016-2017 and thereafter, and a negative fiscal impact on local government revenues of $700,000 in FY 2015-2016 and a recurring $2.7 million in FY 2016-2017 and thereafter.[1] These estimated impacts are anticipated to result from reductions in overall taxable charges to customers and reduced collections of municipal and county public service taxes and franchise fees.[2] Staff notes that these estimated impacts are a result of statutory changes promulgated through the creation of Section 366.95, F.S., as contained in HB 7109, which are beyond the scope of the changes to Commission rules being recommended by staff. Therefore, any economic impacts that might be incurred by affected entities would be a result of statutory changes to Chapter 366, F.S., and not caused by staff's recommended changes to Commission rules.

[1] Florida House of Representatives, Final Bill Analysis – CS/HB 7109, June 12, 2015; page 1.
[2] Id., pp. 14-15.

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

☐ None. The rule will only affect the Commission.

☐ Minimal. Provide a brief explanation.

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

Please refer to Section 2 of the SERC Appendix for a discussion of potential transactional costs that may be associated with the recommended rule revisions.

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

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

☒ No adverse impact on small business. *[See clarification below.]*

☐ Minimal. Provide a brief explanation.

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

Based on a review of investor-owned electric and gas utility annual reports, it is estimated that one gas utility potentially might meet the definition of "small business" as defined in Section 288.703, F.S. However, as noted in Section A above, any economic impacts that might be incurred by affected entities would be a result of statutory changes promulgated under Sections 366.05 and 366.95, F.S., and not caused by staff's recommended changes to Commission rules.

It is difficult to estimate the number of the affected utilities' customers that would meet the definition of "small business" as defined in Section 288.703, F.S. However, as noted in Section A above, any economic impacts that might be incurred by affected entities would be a result of statutory changes promulgated under Sections 366.05 and 366.95, F.S., and not caused by staff's recommended changes to Commission rules.

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

☒ No impact on small cities or small counties.

☐ Minimal. Provide a brief explanation.

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

"Small cities" and "small counties" as defined by Section 120.52, F.S., are not expected to be affected other than in the unlikely scenario where such entities might be direct customers of the affected utilities. However, as noted in Section A above, any economic impacts that might be incurred by affected entities would be a result of statutory changes promulgated under Sections 366.05 and 366.95, F.S., and not caused by staff's recommended changes to Commission rules.

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

☐ None.

<u>Additional Information:</u>
No workshop was requested in conjunction with the recommended rule revisions. Several comments from interested parties were incorporated into the draft rules to provide additional clarification.

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

☒ No regulatory alternatives were submitted.

☐ A regulatory alternative was received from

☐ Adopted in its entirety.

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

Appendix – Statement of Estimated Regulatory Costs Recommended Revisions to Chapters 25-6 and 25-7, F.A.C.

Section 1: Introduction and Summary of Recommended Rule Changes

During the 2015 session, the Florida Legislature enacted House Bill 7109 which was incorporated into Chapter 2015-129, Laws of Florida. Among other things, the legislation added new requirements to Section 366.05, Florida Statutes (F.S.) and created Section 366.95, F.S. These laws became effective on July 1, 2015. To implement the new laws, staff is recommending amendments to Rules 25-6.093 and 25-7.079, F.A.C. (Information to Customers), Rules 25-6.097 and 25-7.083, F.A.C. (Customer Deposits), and Rules 25-6.100 and 25-7.085, F.A.C. (Customer Billings). Rules 25-6.093, 25-6.097, and 25-6.100, F.A.C., apply to investor-owned electric utilities; Rules 25-7.079, 25-7.083, and 25-7.085, F.A.C., apply to investor-owned gas utilities. A summary of the key rule changes is presented below.

The purpose of Rules 25-6.093 and 25-7.079, F.A.C., is to specify the nature of the information that investor-owned electric and gas utilities, respectively, must provide to customers regarding the method of reading meters and the derivation of billing therefrom. Commission Rules 25-6.093 and 25-7.079, F.A.C., are being amended to implement paragraph 366.05(1)(d), F.S. In accordance with the statute, if a utility has more than one rate for any customer class, it must notify each customer in that class of the available rates and explain how the rate is charged to the customer. If a customer contacts the utility seeking assistance in selecting the most advantageous rate, the utility must provide good faith assistance to the customer.

The purpose of Rules 25-6.097 and 25-7.083, F.A.C., is to specify the criteria by which investor-owned electric and gas utilities, respectively, shall determine the amount of customer deposits, establishment of credit, refunding of deposits, payment of interest on deposits, and maintaining records of deposits. Commission Rules 25-6.097 and 25-7.083, F.A.C., are being amended to implement paragraph 366.05(1)(c), F.S. In accordance with the statute, a methodology is prescribed, effective January 1, 2016, that sets a maximum deposit amount that the utility may collect for an existing account or for a new service request.

The purpose of Rules 25-6.100 and 25-7.085, F.A.C., is to specify the criteria that investor-owned electric and gas utilities, respectively, must follow when billing their customers, including billing intervals, the information that must be provided on each bill, procedures for using estimated billing, proration of bills for partial billing periods, and uniformity of application to all customers on the same rate schedule. Commission Rules 25-6.100 and 25-7.085, F.A.C., are being amended to implement paragraph 366.05(1)(b), F.S. In accordance with the statute, if the Commission authorizes a public utility to charge tiered rates based upon levels of usage and to vary its regular billing period, the utility may not charge a customer a higher rate because of an increase in usage attributable to an extension of the billing period; however, the regular meter reading date may not be advanced or postponed more than five days for routine operating reasons without prorating the billing for the period.

Commission Rule 25-6.100, F.A.C., is also being amended to implement subsection 366.95(4), F.S. In accordance with the statute, if an electric utility has obtained a financing order and caused nuclear asset-recovery bonds to be issued, the utility's electric bills must: (1) explicitly reflect information explaining the nuclear asset-recovery charge and the ownership of that charge, and (2) show a separate line item titled "Asset Securitization Charge" on each customer's bill that includes both the rate and the amount of the charge.

Section 2: Discussion of Estimated Additional Transactional Costs

Staff is recommending amendments to the rules noted in Section 1 above so that Commission rules will continue to be consistent with the requirements of the empowering statutes as revised during the 2015 legislative session. Therefore, any economic impacts that might be incurred by affected entities would be a result of statutory changes promulgated under Sections 366.05 and 366.95, F.S., and not caused by staff's recommended changes to Commission rules.

To compile this SERC, staff gathered information from internal and external sources. To identify potential additional transactional costs that might be incurred by affected entities, staff sent a data request to all investor-owned electric (5) and gas (8) utilities under the jurisdiction of the Commission. A summary of the information provided in response to staff's data request is presented below in Table 1. Because the estimated additional transactional costs are caused by statutory changes and not staff's recommended changes to Commission rules, none of the rule impact/cost criteria established in paragraph 120.541(2)(a), F.S., will be exceeded as a result of the recommended rule revisions.

Table 1
Summary of Estimated Additional Transactional Costs

Changes to Statute (F.S.) [eff. 7/1/15]	Associated Changes to Rules (F.A.C.)	Items Affected by Statutory Changes	2015 Costs[1] ($000)	2016-19 Costs ($000)	Total Costs[2] ($000)
366.05(1)(d)	25-6.093, 25-7.079	Information to Customers	0	0	0
366.05(1)(c)	25-6.097, 25-7.083	Customer Deposits	1,263	183	1,446
366.05(1)(b)	25-6.100, 25-7.085	Customer Billings	6	0	6
366.95(4)	25-6.100	Customer Billings	628	337	965
			1,897	**520**	**2,417**

Source: Electric and gas utility responses to staff's data request, October 2015.

Based upon the utilities' responses to staff's data request, approximately $2.412 million of the estimated $2.417 million (99.8 percent) in additional costs is expected to be incurred by electric

[1] First-year costs [paragraph 120.541(1)(b), F.S.].
[2] Five-year costs [subparagraph 120.541(2)(a)3, F.S.].

utilities. One gas utility estimated incremental costs of approximately $5,000 to comply with the changes to paragraph 366.05(1)(c), F.S.

Discussion of Specific Additional Transactional Cost Estimates

Information provided in the data request responses was combined with staff's analysis and the results are discussed below. The four major subject areas covered by this rulemaking initiative are identified individually by statutory reference, associated Commission rule(s), and subject matter area.

Paragraph 366.05(1)(d), F.S., Rules 25-6.093 and 25-7.079, F.A.C., Information to Customers

Based on the data request responses, utilities indicated that they did not expect additional transactional costs in association with the requirements to notify customers that have multiple rate options available. One utility expressed a concern that significant additional transactional costs could be incurred if the meaning of the term "bill insert" as used in paragraph 25-6.093(3)(a), F.A.C., were limited to only print notification. Staff concurs with the utility's interpretation that the term "bill insert" provides for customer notification through electronic format for customers enrolled in email bill programs.

Paragraph 366.05(1)(c), F.S., Rules 25-6.097 and 25-7.083, F.A.C., Customer Deposits

Four electric utilities and one gas utility provided estimates of additional costs yielding a combined total of $1.446 million to comply with the new methodology prescribed by statute that sets a maximum deposit amount that a utility may collect for an existing account or for a new service request. Of the total, $1.296 million (90 percent) represent front-end costs associated with system reprogramming, coding, and testing changes to allow for: (a) evaluation of accounts and to apply or refund excess deposit amounts, (b) creation of system detail files to track activity and compliance and enhance reporting, and (c) regularly scheduled usage reviews to determine if existing deposits are adequately secured. One electric utility also estimated recurring costs of $0.20 per unit for postage associated with the increased volume of deposit certificates that will be sent whenever there is a change to a customer deposit. The utility estimated an annual volume of 150,000 units, yielding an incremental cost of $30,000 per year over the next five years ($150,000 total). Seven gas utilities and one electric utility projected that they would not incur additional costs to comply with the new deposit requirements.

Paragraph 366.05(1)(b), F.S., Rules 25-6.100 and 25.7-085, F.A.C., Customer Billings

Based on the data request responses, 12 of 13 utilities indicated that they did not expect additional transactional costs in association with the requirements to not charge customers higher-tiered rates because of an increase in usage attributable to an extension of the billing period. One electric utility estimated approximately $6,000 in front-end costs to change the programming logic to expand the first tier to allow greater than 1,000 kilowatt-hours if necessary to accommodate additional usage resulting from an extension of the billing period.

Subsection 366.95(4), F.S., Rule 25-6.100, F.A.C., Customer Billings (nuclear "asset securitization charge")

Subsection 366.95(4), F.S., applies only to electric utilities that have obtained financing orders and caused nuclear asset-recovery bonds to be issued. One utility estimated approximately $965,000 in total incremental costs to manage the customer billing requirements to enable its customer bills to show an explanation of the nuclear asset-recovery charge and the ownership of that charge, and to show a separate line item on each customer's bill for the asset securitization charge. Another utility with nuclear generation assets stated that it did not currently anticipate requesting a financing order for nuclear asset recovery bonds within the next five years. However, the utility estimated that if it were to initiate such changes today, its costs to comply with the new billing requirements would be approximately $1 million.

Item 3

FILED NOV 18, 2015
DOCUMENT NO. 07310-15
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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Office of the General Counsel (Tan, Lherisson)
Division of Accounting and Finance (Buys)
Division of Economics (Thompson)
Division of Engineering (King)

RE: Docket No. 150026-WS – Complaint by Eagleridge I, LLC against Lake Utility Services, Inc. for declaration that connections have been made and all amounts due have been paid, and mandatory injunction requiring refund of amounts paid under protest.

AGENDA: 12/03/15 – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brisé

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

Eagleridge I, LLC (Eagleridge), is a Florida Limited Liability Company which develops properties in Lake County, Florida. Lake Utility Services, Inc. (LUSI), is a utility company providing water and wastewater service in Lake County, Florida, and is a wholly owned subsidiary of Utilities, Inc. Eagleridge developed a parcel of commercial property (the Development) located on U.S. Highway 27 in Clermont, Florida. The Development is commonly known as Golden Eagle Village, which consists of a Publix-anchored shopping center.

On April 29, 2010, Eagleridge entered into a letter agreement (the Contract) with LUSI. A copy of the Contract is attached as Attachment A. Pursuant to the Contract, in exchange for LUSI providing water and wastewater utility services to the Development, Eagleridge agreed to pay an up-front System Capacity Charge in the amount of $87,242.36, Plan Review Fees in the amount of $300, and Inspection Fees in the amount of $150. The System Capacity Charges were based on the utility's approved water and wastewater plant capacity charges and the projected demand for the Development. In addition, Eagleridge was responsible for constructing the on-site water and wastewater lines necessary to connect the Development to the utility's existing lines, consistent with the utility's approved main extension policy. Eagleridge paid all fees and charges identified in the Contract. The Contract also contains waiver language, in pertinent part:

> In consideration of this contribution, [LUSI] waive all other tap fees/connection fees. Water and wastewater usage charges will be levied in accordance with our authorized tariff as required and approved by the Florida Public Service Commission.

Eagleridge proceeded with the Development, including obtaining all necessary permits. On August 10, 2010, Eagleridge applied for a Florida Department of Environmental Protection (DEP) permit to construct a wastewater collection line from the utility's existing collection system to the Development. In March 2011, Eagleridge submitted to DEP its Request for Approval to Place a Domestic Wastewater Collection/Transmission System into Operation. A copy of the Request for Approval is attached as Attachment B. On March 18, 2011, Patrick Flynn, LUSI's Regional Director, signed the Request for Approval certifying to DEP that all connections to LUSI's wastewater facility had been completed to LUSI's satisfaction. On March 31, 2011, the DEP granted Eagleridge's application and the connection between the Development and LUSI's wastewater system was completed in April 2011.

On November 3, 2011, the Commission granted LUSI's application for increase in water and wastewater rates.[1] Before the Commission revised LUSI's main extension charge, the main extension charge was negotiable. The Commission also revised the utility's water plant capacity and water and wastewater main extension charges. According to the order, LUSI's wastewater service availability policy provided that developers would install new collection lines and donate them to the utility. The Commission approved a wastewater main extension charge that would allow the utility to collect the appropriate charge from a single property owner in lieu of donated lines.

On March 4, 2013, LUSI wrote a letter to Eagleridge stating that the Commission granted LUSI the right to increase its wastewater main extension charge. LUSI's letter further stated that the new charge applied to the balance of the prepaid capacity fees for units that had yet to be connected for service. LUSI requested an additional main extension charge of $63,625.20 based on the new main extension charges of $4.44 per gallon ($1,243/280 gallons per equivalent residential connection) and 14,330 gallons of reserved capacity yet to be assigned. The March 4, 2013, letter is attached as Attachment C.

The parties dispute whether LUSI is entitled to charge the increased wastewater main extension charge to Eagleridge. Eagleridge, relying on Rule 25-30.475, Florida Administrative Code

[1] See Order PSC-11-0514-PAA-WS, issued November 3, 2011, in Docket No. 100426-WS, In re: Application for increase in water and wastewater rates in Lake County by Lake Utility Services, Inc. (November 2011 Order)

(F.A.C.), argues that LUSI "may not charge the fees for services rendered or connections made prior to the effective date of the PSC Order."[2] The parties unsuccessfully attempted to resolve the dispute. Eagleridge, under protest, paid the increased fees to LUSI. Eagleridge has recently sold the Development, but Eagleridge has retained all rights to pursue and recover a refund of the subject disputed fees.[3]

On January 8, 2015, Eagleridge filed a complaint with the Commission requesting (i) a declaration that the fees are not applicable to Eagleridge where connections already have been made; (ii) a declaration that all amounts due and owing for service availability charges and connection fees have been paid by Eagleridge; and (iii) an order directing LUSI to immediately refund all monies paid under protest.[4] On January 20, 2015, LUSI filed a response to Eagleridge's complaint with the Commission.[5] Staff, in order to facilitate the review of the complaint filed by Eagleridge, issued a Data Request to LUSI.[6] LUSI responded to staff's Data Request by letter.[7] On April 3, 2015, Staff held a conference call for the parties to discuss the complaint.[8] Eagleridge subsequently filed a supplemental filing in response to LUSI's answer to the complaint, LUSI's answer to staff's first data request, and LUSI's response to staff's questioning during the conference call.[9]

The Commission has jurisdiction over this matter pursuant to Chapter 367, Florida Statutes (F.S.) and Rule 25-30, F.A.C.

[2] See November 2011 Order.
[3] Id.
[4] Id.
[5] Document No. 00342-15, in Docket No. 150026-WS, Lake Utility Services, Inc.'s Answer to Complaint.
[6] Document No. 00817-15, in Docket No. 150026-WS, Staff Data Request.
[7] Document No. 00996-15, in Docket No. 150026-WS, Lake Utility Services, Inc.'s responses to the Staff's First Data Request.
[8] Document No. 01788-15, in Docket No. 150026-WS, Memo to all parties and interested persons advising of a conference to discuss the complaint.
[9] Document No. 02038-15, in Docket No. 150026-WS, Eagleridge I, LLC's Supplemental Filing In Response To Lake Utility Services, Inc.'s Answer To Complaint And Answer To Staff's First Data Request And Response To Staff's Questioning During April 3, 2015 Conference.

Discussion of Issues

Issue 1: Did Lake Utility Services, Inc., appropriately charge increased fees to Eagleridge I, LLC?

Recommendation: No. Staff recommends that the Commission find that it was not appropriate for LUSI to charge increased fees to Eagleridge I, LLC. (Tan, Lherisson, Thompson, King)

Staff Analysis: To determine whether LUSI appropriately charged increased fees to Eagleridge, staff reviewed the Contract, supporting documents, the date of connection, and Commission Rules. Both parties believe, pursuant to Rule 25-30.475(2), F.A.C., unless authorized by the Commission and provided that customers have received notice, non-recurring charges, such as service availability charges, shall be effective for service rendered or connections made on or after the stamped approval date on the tariff sheets. Staff believes the crux of this complaint is whether the wastewater connection was completed prior to the new wastewater service availability charge ordered by the Commission.

Eagleridge's Complaint

Eagleridge believes that the wastewater main extension charge of $63,625.20 paid to LUSI under protest should be refunded because the Development was connected to the utility's collection system in April 2011, prior to the Commission approving a new main extension charge for LUSI in November 2011. To support its argument, Eagleridge argues that (1) the contract provided that all other tap fees/connection fees would be waived in consideration of Eagleridge's payment of the service availability charges, (2) all connections to LUSI's wastewater system were made in April 2011 prior to the increase in service availability charges, and (3) LUSI was explicitly prohibited by Commission Rules and Order No. PSC-11-0514-PAA-WS (November 2011 Order) from charging the new service availability charge. Eagleridge argues that Rules 25-30.210, and 25-30.515, F.A.C., and Eager v. Florida Keys Aqueduct Authority, 580 So. 2d 771 (Fla. 3d DCA 1991), support their request for refund.

Pursuant to Rule 25-30.210(4), F.A.C., "service pipe" is defined as the pipe between the utility's main and the point of delivery, including the "pipe, fittings, and valves necessary to make the connection excluding the meter." Eagleridge argues that Rule 25-30.210(6), F.A.C., applies because the Rule provides that "point of delivery" is where the service pipe is connected to the utility company's main. Regarding service availability policies or contracts, Rule 25-30.515(1), F.A.C., provides "active connection means a connection to the utility's system at the point of delivery of service, whether or not service is currently being provided." In August 2010, Eagleridge applied for a DEP permit to construct a wastewater collection line from the utility's existing collection system to the Development. In March 2011, Eagleridge submitted its Request for Approval to Place a Domestic Wastewater Collection/Transmission System into Operation to DEP. DEP approved Eagleridge's request to place its wastewater main extension to LUSI's collection system into service.

Eagleridge believes that the Contract contains a waiver of additional fees, in pertinent part:

> In consideration of this contribution, we waive all other tap fees/connection fees. Water and wastewater usage charges will be levied in accordance with our authorized tariff as required and approved by the Florida Public Service Commission.

Eagleridge believes that this waiver provides that "all other 'tap fees/connection fees' would be 'waived,' while any water and wastewater usage charges would be levied as approved by the [Commission]."[10] Eagleridge believes that LUSI "does not have any legitimate basis to charge the fees to Eagleridge . . . [and] the water and wastewater connections have already been made and, by rule (i.e., Florida Administrative Code) and the PSC Order, LUSI is prohibited from charging the Fee to Eagleridge."[11]

Further, Eagleridge argues that, pursuant to Eager, the Commission should apply the "plain and unambiguous language in the [F.A.C.] to find that the connections were completed when LUSI's service pipe was connected to Eagleridge's piping." Eagleridge argues that "LUSI is requesting that the [Commission] ignore the plain language of the [F.A.C.] under the guise of 'interpretation.'" Eagleridge believes that the Commission is obligated to apply the plain and unambiguous language of the F.A.C., which provides that a connection is completed when the utility's service pipe is connected with the customer whether or not service is currently being provided.

LUSI's Response

LUSI believes that it is entitled to collect the wastewater main extension charge approved by the Commission for the portion of the Development not yet receiving water service. To support its argument, LUSI argues that (1) the utility did not waive the right to collect the increased charges and (2) not all connections had been made when the increased charges were implemented. LUSI references H. Miller & Sons v. Hawkins, 373 So. 2d 913 (Fla. 1979), and Rules 25-30.210, and 25-30.515, F.A.C., in support of their arguments.

Citing H. Miller & Sons v. Hawkins, LUSI argues that contracts with public utilities are made subject to the reserved authority of the state, under the police power of express statutory or constitutional authority, to modify the contract in the interest of the public welfare without unconstitutional impairment of contracts. Regarding the waiver contained in the Contract, LUSI believes Eagleridge "misconstrues the waiver language" in that the "meaning of the waiver is that LUSI waived any other tap fees/connection fees that were in existence at that time" and "there is no significance in the language regarding usage charges."[12] LUSI argues that the waiver language relates to any other tap fees/connection fees that were in existence at the time the contract was signed.

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[10] Document No. 00148-15, in Docket No. 150026-WS, Complaint Requesting Declaration That Connections Have Been Made and All Amounts Due Have Been Paid and Mandatory Injunction Requiring Refund Of Amounts Paid Under Protest.
[11] Id.
[12] Document No. 00342-15, in Docket No. 150026-WS, Lake Utility Services, Inc.'s Answer to Complaint.

LUSI argues that Rule 25-30.210(7), F.A.C., should apply when determining the definition of "point of delivery." Rule 25-30.210(7), F.A.C., provides "'point of delivery' for water systems shall mean the outlet connection of the meter for metered service or the point at which the utility's piping connects with the customer's piping for non-metered service."

While LUSI believes that "[a] connection is not a connection for purposes of applying increases in service availability charges unless service has been previously implemented . . . the actual cost of maintaining sufficient capacity cannot be determined until the date that service actually initially commences."[13] LUSI argues that "unless water service is active there can be no wastewater flow and therefore, no wastewater service is provided." LUSI contends that a connection within the Eagleridge Development occurs only when a meter is installed after service is requested. Increasing service availability charges prevents current customers from subsidizing costs associated with future plant capacity. Referencing Rule 25-30.515(9), F.A.C., LUSI argues that Guaranteed Revenue Charges are designed to help the utility recover part of its cost from the time capacity is reserved until a customer begins to pay monthly service rates.

Analysis

Waiver of Fees

Pursuant to the Contract, Eagleridge paid an up-front System Capacity charge, Plan Review Fees, and Inspection Fees to LUSI. The Contract included language which Eagleridge believes is a waiver of additional "tap fees/connection fees," in pertinent part: "[i]n consideration of this contribution, [LUSI] waive all other tap fees/connection fees. Water and wastewater usage charges will be levied in accordance with our authorized tariff as required and approved by the Florida Public Service Commission." LUSI argues that the waiver language related to any other tap fees/connection fees that were in existence at the time the contract was signed. Pursuant to 367.011(2), F.S., the Commission has "exclusive jurisdiction over each utility with respect to its authority, service, and rates." Staff believes that the waiver language in the Contract would be insufficient to prevent LUSI from collecting fees when appropriate.

Donated Lines

The change the Commission approved in the utility's wastewater main extension charge in November 2011 was merely to provide a charge that would be applicable to individual customers. Prior to the November 2011 Order, the utility's approved main extension policy allowed the utility to receive donated lines from a developer, but did not address the appropriate charge for a wastewater customer connecting to a main constructed by the utility.[14] In that Order, the Commission approved a wastewater main extension charge that would allow the utility to collect the appropriate charge from a single property owner in lieu of donated lines.[15] Therefore, the main extension charge was not intended to be collected from a developer, such as Eagleridge, who constructed and donated a collection line to the utility. Staff believes this means that since Eagleridge donated its lines, a charge cannot be assessed.

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[13] Document No. 00342-15, in Docket No. 150026-WS, Lake Utility Services, Inc.'s Answer to Complaint.
[14] November 2011 Order.
[15] Id. at 39.

Active Connection

Rule 25-30.210(6) and (7), F.A.C., define "point of delivery." Staff believes that in this case the "point of delivery" for wastewater service is where the service pipe is connected to the utility company's main, as defined in Rule 25-30.210(6), F.A.C. Subsection (7) addresses "point of delivery" for a water system; therefore, it does not apply to this docket.

Pursuant to Rule 25-30.515(1), F.A.C., an "active connection means a connection to the utility's system at the point of delivery of service, whether or not service is currently being provided." Although it is LUSI's contention than an active connection was not made, in March 2011, DEP approved Eagleridge's request to place its wastewater main extension to LUSI's collection system into service. The DEP approval included the consent and understanding of the utility. Staff believes that an active wastewater connection was made when the physical connection was completed, even though water service has not been provided to the entire Development. If DEP had not accepted the line into operation, staff believes, as mentioned above, that the terms in the Contract that parties refer to as a waiver would be insufficient to prevent LUSI from collecting fees. However, that is not the situation in this docket.

Status of Contract

To determine whether LUSI appropriately charged increased fees to Eagleridge, staff assessed the status of the Contract at the time the fees were levied. Pursuant to our rules, staff believes that the Contract was fulfilled because (1) Eagleridge paid the up-front System Capacity Charge, including the other fees identified in the contract, when signed in April 2010; (2) the main extension charge should not have been charged because Eagleridge constructed and donated a collection line to the utility; and (3) LUSI's piping was connected to Eagleridge's Development and both DEP and the utility signed off on the active connection. Thus, it was an error for LUSI to charge Eagleridge $63,625.20 in addition to what was contemplated in the Contract. Staff's analysis would end here if LUSI did not raise the argument that H. Miller & Sons applies to this docket.

Applicability of H. Miller & Sons

LUSI argues that under H. Miller & Sons, Inc. v. Hawkins, LUSI is permitted to increase service availability charges because the Commission has authority to change rates in a private contract between a utility and developer. In H. Miller & Sons, the developer, H. Miller and Sons, Inc., entered into an agreement with Cooper City Utilities, Inc., to obtain water and sewer utility service for a 500-unit subdivision. In early 1975, Miller completed the payments in accordance with the agreement. However, not all of the homes were connected to the utility system. In late 1975, the Commission, in Order No. 6953, issued on October 9, 1975, in Docket No. 750368-WS, In Re: Application of Cooper City Utilities, Inc., For Approval of Tariff Modifications, authorized the Utility to increase its wastewater main extension charges.

In H. Miller & Sons, the Supreme Court of Florida affirmed the Commission's decision to modify the contract in the interest of the public welfare based on the principle that contracts with public utilities are subject to the reserved authority of the state.[16] The Commission ordered Miller to "pay for all connections added to the Cooper City Utility Water and Sewer System after the effective date of Order No. 6953."[17]

The Commission has applied H. Miller & Sons in over 40 cases. In an Order issued in 2001, as well as in fourteen prior Orders, the Commission referenced H. Miller & Sons to explain "applicable service availability charges are those in effect at the time of actual connection, because the actual cost of maintaining sufficient capacity cannot be ascertained until that date."[18]

Staff believes that LUSI would be correct that H. Miller & Sons applies only if the connection with Eagleridge had not yet been made at the time the Commission granted LUSI's application for increase in water and wastewater rates. Staff believes that H. Miller & Sons is not applicable in this case because three events occurred before the Commission granted a rate increase: (i) Eagleridge paid the up-front System Capacity Charge, including the other fees identified in the contract; (ii) LUSI's piping was connected to Eagleridge's Development; and (iii) DEP and the utility signed off on the active connection. Therefore, staff believes the Contract was fulfilled and LUSI charged increased fees to Eagleridge in error.

Conclusion

Staff recommends that the Commission find that it was not appropriate for LUSI to charge increased fees to Eagleridge I, LLC.

[16] H. Miller & Sons, 373 So. 2d at 915.
[17] Order No. 7650, issued February 21, 1977, in Docket No. 760299-WS, In re: H. Miller and Sons, Inc. v. Cooper City Utilities, Inc.
[18] Order No. PSC-01-0857-PAA-WS, issued April 2, 2001, in Docket No. 000610-WS, In re: Application for uniform service availability charges in Duval, Nassau, and St. Johns Counties by United Water Florida, Inc.

Issue 2: Is a refund appropriate?

Recommendation: Yes. Staff recommends that the full amount of $63,625.20, plus interest, should be refunded to Eagleridge, pursuant to 25-30.360, F.A.C. (Tan, Lherisson, Buys)

Staff Analysis: On March 4, 2013, LUSI requested that Eagleridge remit an additional $63,625.20 in Wastewater Main Extension Charges. Although Eagleridge disputed the amount, the company paid the amount to LUSI. As part of the complaint, Eagleridge has asked for the full $63,625.20 to be refunded back to them.

If the Commission supports staff's recommendation in Issue 1, the full $63,625.20 should be returned back to Eagleridge with interest, pursuant to Rule 25-30.360(1). In addition, Rule 25-30.360(2), F.A.C., contemplates that the refund amount should be returned within 90 days of the final Commission Order. Staff recommends that interest shall be calculated pursuant to Rule 25-30.360(4), F.A.C., to the amount of $1,737.32. If the Commission disagrees with staff's recommendation, staff recommends that no refund is required.

Therefore, Staff recommends that the full amount of $63,625.20, plus interest to the amount of $1,737.32, should be refunded to Eagleridge, pursuant to 25-30.360, F.A.C.

Issue 3: Should this docket be closed?

Recommendation: No. Staff recommends that if the Commission supports staff's recommendation in Issues 1 and 2, this docket should remain open until the completion of the refund to Eagleridge. Upon staff's verification that the refund has been completed, this docket should be administratively closed. If the Commission disagrees with staff's recommendation on Issues 1 and 2, this docket should be closed upon issuance of the Consummating Order. (Tan, Lherisson)

Staff Analysis: Staff recommends that if the Commission supports staff's recommendation in Issues 1 and 2, this docket should remain open until the completion of the refund to Eagleridge. Upon staff's verification that the refund has been completed, this docket should be administratively closed. If the Commission disagrees with staff's recommendation on Issues 1 and 2, this docket should be closed upon issuance of the Consummating Order.

Utilities, Inc.

April 29, 2010

Mr. Daniel Butts, Senior Vice President
~~BPL Eagleridge, L.L.C.~~ Eagleridge I, LLC
P.O. Box 3010
Winter Park, FL 32790

Re: Golden Eagle Village - Phase 1
US Highway 27
Clermont, Florida

Dear Mr. Butts:

As requested, our Company, Lake Utility Services, Inc. is willing to make water and wastewater utility service available to Phase 1 of the Golden Eagle Village in Lake County, Florida. It is our understanding that the project will consist of a 46,031 square foot grocery store, a combined 12,650 square foot building space for mixed retail and 5,800 square foot of building space with 387 seats for restaurant use.

As the Owner, the ~~BPL Eagleridge, L.L.C.~~ Eagleridge I, LLC will be responsible for the construction and installation of all necessary on-site water and wastewater collection facilities such as water services, water mains, fire hydrants, manholes, service laterals, valves and other facilities reasonably required to provide adequate utility service to your project. All facilities will be extended by the ~~BPL Eagleridge, L.L.C.~~ Eagleridge I, LLC to our existing 8" sanitary lateral located in the Lake County right of way on Eagle Ridge Boulevard and 12" potable water main also located within the right of way on Eagle Ridge Boulevard and the FDOT right of way on U.S. Highway 27 per utility plans.

All facilities installed by Owner will be in accordance with all governmental specifications and in conformance with the construction standards utilized in our existing facilities. Owner will indemnify our Company from any liability incurred during the installation of these facilities. All of the on-site and off-site sanitary facilities constructed up to the point of connection under the agreement shall remain under the ownership and responsibility of the Owner. All of the on-site and off-site water facilities up to the point of connection to each meter, as well as all necessary easements, shall be transferred to our Company at no cost. Plans and specifications will be submitted to our Company for review, and shall have received the written approval of our Company before construction is begun, which approval shall not be unreasonably withheld or delayed.

We are willing to provide the requested utility service in consideration of an up front System Capacity Charge in the amount of $87,242.36, $300 Plan Review Fee, and $150 Inspection Fee. This reservation of capacity fee is based on your requested utility capacity requirements as provided through (7) 5/8" water meters, (5) 1.5" water meters, (1) 2" water meter and an 8" sanitary lateral. Meter and account set up fees will be assessed at the time of application. In consideration of this contribution, we waive all other tap fees/connection fees. Water and wastewater usage charges will be levied in accordance with our authorized tariff as regulated and approved by the Florida Public Service Commission.

a Utilities, Inc. company Lake Utility Services, Inc.
200 Weathersfield Ave. • Altamonte Springs, FL 32714-4027 • P:407-869-1919 • F:407-869-6961 • www.uiwater.com

Mr. Butts
Page 2
April 29, 2010

Eagleridge I, LLC

If this proposal is acceptable to the ~~BPL Eagleridge, L.L.C.~~, please sign and forward the original of this letter along with the required $87,692.36 payment by May14, 2010 to the attention of Bryan K. Gongre in our Altamonte Springs office.

If you have any other questions or concerns, please contact Bryan at 1.800.272.1919, extension 1360.

Sincerely,

LAKE UTILITY SERVICES, INC.

Richard J. Durham
Regional Vice President

Accepted: Daniel H. Butts

Witness: Deborah B Crupe

ec: Patrick Flynn, Regional Director

Florida Department of Environmental Protection
Twin Towers Office Bldg., 2600 Blair Stone Road, Tallahassee, Florida 32399-2400

REQUEST FOR APPROVAL TO PLACE A DOMESTIC WASTEWATER COLLECTION/TRANSMISSION SYSTEM INTO OPERATION

PART I - INSTRUCTIONS

(1) This form shall be completed and submitted to the appropriate DEP district office or delegated local program for all collection/transmission system projects required to obtain a construction permit in accordance with Chapter 62-604, F.A.C.

(2) Newly constructed or modified collection/transmission facilities shall not be placed into service until the Department has cleared the project for use.

RECEIVED
MAR 29 2011
DEP Central Dist.

(3) All information shall be typed or printed in ink, and all blanks must be filled.

PART II - PROJECT DOCUMENTATION

(1) Collection/Transmission System Permittee

Name: Mr. Daniel Butts Title: Senior Vice President
Company Name: Eagleridge I, LLC
Address: PO Box 3010
City: Winter Park State: FL Zip: 32790-3010
Telephone: (407) 622-1700 Fax: (407) 622-1717 Email: daniel@battagliagroup.com

(2) General Project Information

Project Name: Golden Eagle Village Phase 1
Construction Permit No.: 0302221-001 Dated: August 10, 2010

Is the entire project included under the collection/transmission system permit substantially complete? ☒ Yes ☐ No (If approval is being requested to place a portion of the project into operation, attach a copy of the site plan or sketch that was submitted with the application showing the portion of the project which is substantially complete and for which approval is being requested.)

Description of Portion of Project for Which Approval is Being Requested (including pipe length, total number of manholes and total number of pump stations): 2,491 LF of 8" PVC pipe, 19 manholes, and 0 pump stations

Expected Date of Connection to Existing System or Treatment Plant: April 2011

(3) Treatment Plant Serving Collection/Transmission System

Name of Treatment Plant Serving Project: Lake Groves WWTF
County: Lake City: Clermont
DEP permit number: FL FLA010630-005-DW1 Expiration Date: 08/06/2012

emailed 4-1-11 (S)

Final

For Department Use Only
Date: 3-31-11 4/1/2011
By: [illegible]
CLEARED FOR USE
E-filed

DEP Form 62-604.300(8)(b)
Effective November 6, 2003

Page 1 of 3

Northwest District | Northeast District | Central District | Southwest District | South District | Southeast District
[illegible]

PART III - CERTIFICATIONS

(1) Collection/Transmission System Permittee

I, the undersigned owner or authorized representative* of Eagleridge I, LLC certify that the engineer has provided us a copy of the record drawings for this project and if there is not already an existing applicable operation and maintenance (O&M) manual, one has been prepared for the new or modified facilities.

Also, I certify that, if we will not be the owner of this project after it is placed into service, we have provided a copy of the above mentioned record drawings and a copy of the above mentioned O&M manual, if applicable, to the person or system that will be the owner of this project after it is placed into service.

Signed Daniel Butts Date 3/14/11
Name Daniel Butts Title Senior Vice President

Attach a letter of authorization.

(2) Owner of Collection/Transmission System After it is Placed into Service

I, the undersigned owner or authorized representative* of Eagleridge I, LLC certify that we accept the project as constructed and will be the owner of this project after it is placed into service. I agree to report any abnormal events in accordance with Rule 62-604.550, F.A.C. and promptly notify the Department if we sell or legally transfer ownership of the collection/transmission system. Also I certify that we agree to operate and maintain the facilities in accordance with the provisions of Chapter 403 Florida Statutes (F.S.) and applicable Department rules and that we have received a copy of the record drawings and O&M manual for this project and that these record drawings and O&M manual are available at the following location which is within the boundaries of the district office or delegated local program permitting the collection/transmission system:

Signed Daniel Butts Date 3/14/11
Name Daniel Butts Title Senior Vice President
Company Name BPL Eagleridge, LLC
Address PO Box 3010
City Winter Park State FL Zip 32790-3010
Telephone (407) 622-1700 Fax (407) 622-1717 Email daniel@battagliagroup.com

Attach a letter of authorization.

(3) Wastewater Facility Serving Collection/Transmission System

I, the undersigned owner or authorized representative* of the Lake Groves WWTF Wastewater facility hereby certify that the above referenced facility has adequate reserve capacity to accept the flow from this project and will provide the necessary treatment and disposal as required by Chapter 403, F.S., and applicable Department rules. Also, I certify that any connections associated with this project to the above referenced facility, which we operate and maintain, have been completed to our satisfaction and we have received a copy of the record drawings for this project.

Signed Patrick C Flynn Date 3/18/11
Name Patrick Flynn Title Regional Director
Address 200 Weathersfield Ave.
City Altamonte Springs State FL Zip 32714
Telephone (407) 869-1919 Fax (407) 869-6961 Email pcflynn@uiwater.com

Attach a letter of authorization.

DEP Form 62-604.300(8)(b)
Effective November 6, 2003

Page 2 of 3

(4) Professional Engineer Registered in Florida

I, the undersigned professional engineer registered in Florida, certify the following:

- that this project has been constructed in accordance with the construction permit and engineering plans and specifications or that, to the best of my knowledge and belief, any deviations from the construction permit and engineering plans and specifications will not prevent this project from functioning in compliance with Chapter 62-604, F.A.C.;
- that the record drawings for this project are adequate and include substantial deviations** from the construction permit and engineering plans and specifications;
- that a copy of the record drawings has been provided to the permittee and to the wastewater treatment facility serving the collection/transmission system;
- that the O&M manual for this project has been prepared or examined by me, or by an individual(s) under my direct supervision, and that there is reasonable assurance, in my professional judgment, that the facilities, when properly maintained and operated in accordance with this manual, will function as intended; and
- that, to the best of my knowledge and belief, appropriate leakage tests have been performed and the new or modified facilities met the specified requirements.

This certification is based upon on-site observation of construction conducted by me or by a project representative under my direct supervision and upon a review of shop drawings, test results/records, and record drawings performed by me or by a project representative under my direct supervision.

The following is a description and explanation of substantial deviations** from the construction permit and engineering plans and specifications for the substantially completed portion of this project. (Attach additional sheets if necessary.)

None.

JOHN B. PROWELL LICENSE NO. 59469 STATE OF FLORIDA PROFESSIONAL ENGINEER

Signed [signature]
Date 3-18-11

Name John Prowell Florida Registration No. 0059469
Company Name VHB Miller Sellen
Address 225 E. Robinson Street, Suite 300
City Orlando State FL Zip 32801
Telephone (407) 839-4006 Fax (407) 839-4008 Email jprowell@vhb.com

*** Substantial deviations are construction deviations greater than 10% from plans and specifications and any deviations which fall below minimum standards established in Rule 62-604, F.A.C.*

DEP Form 62-604.300(8)(b)
Effective November 6, 2003

Page 3 of 3

Utilities, Inc.

March 4, 2013

Ms. Shannon Mitchell
BPL Eagleridge, LLC
P.O. Box 3010
Winter Park, FL 32790

RE: Golden Eagle Village - Phase 1
Increase in Wastewater Main Extension Charges

Dear Ms. Mitchell:

In December 2011, the Florida Public Service Commission granted Lake Utility Services, Inc. an increase in the amount of Wastewater Main Extension Charges that the Utility is entitled to recover per gallon of General Service (commercial) customers.

Per ERC	**Previous Rate**	**New Rate**
Main Extension	$ none	$4.44/gallon
Net Increase		$4.44/gallon

This charge will be applied to the balance of the prepaid capacity fees for units that have yet to be connected for service. Our conversation the week of 2/25/2013 verified the number of units currently being served and their assigned capacity within the Golden Eagle Village indicating that there is 14,330 gallons of reserved capacity yet to be assigned. I have enclosed a spreadsheet with the breakdown. As a result, BPL Eagleridge, LLC will need to remit $63,625.20 ($4.44 x 14,330 gallons) in Wastewater Main Extension Charges. This amount will need to be received by Lake Utility Services, Inc. prior to any new meters being set within the project.

Should you have any questions, please feel free to contact me by calling 800.272.1919, extension 1360.

Sincerely,
LAKE UTILITY SERVICES, INC.

Bryan K. Gongre

Bryan K. Gongre
Regional Manager

Enclosure

a Utilities, Inc. company Lake Utility Services, Inc.

200 Weathersfield Ave. • Altamonte Springs, FL 32714-4027 • P:407-869-1919 • F:407-869-6961 • www.uiwater.com

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: November 20, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (Barrett, Bulecza-Banks, Lester) MCB ALM
Division of Economics (Draper) EJD
Division of Engineering (Matthews)
Office of the General Counsel (Brownless, Janjic, Villafrate)

RE: Docket No. 150001-EI – Fuel and purchased power cost recovery clause with generating performance incentive factor.

AGENDA: 12/03/15 – Regular Agenda – Post Hearing Decision – Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: Decision must be rendered by 12/03/15 in order to implement new fuel factors with the first billing cycle in 2016.

SPECIAL INSTRUCTIONS: None

Table of Contents

Case Background

As part of the continuing fuel and purchased power adjustment and generating performance incentive factor clause proceedings, an administrative hearing was held on November 2-3, 2015. At the hearing, certain stipulated issues for Tampa Electric Company (TECO), Gulf Power Company (Gulf), Florida Power & Light Company (FPL), Florida Public Utilities Company (FPUC), and Duke Energy Florida, LLC. (DEF) were approved by bench decision. Although the Commission approved some stipulated issues for each of these investor-owned utilities (IOUs), testimony and other evidence was presented at the November 2-3, 2015 hearing for Issues 1D, 1E, 2B, 3B, 3K, 5B, and 6B (hedging-related issues for the generating IOUs), and also for Issues 4A and 4B, which are company-specific issues for FPUC.[1] TECO, Gulf, FPL, FPUC, DEF, Florida Industrial Power Users Group (FIPUG), the Office of Public Counsel (OPC), and PCS Phosphate (PCS) filed briefs on November 13, 2015.[2]

The Commission has jurisdiction over this subject matter pursuant to the provisions of Chapter 366, Florida Statutes (F.S.), including Sections 366.04, 366.05, and 366.06, F.S.

[1]Staff notes that Issues 8-12, 19, 21, and 23 remain open for FPUC and are addressed in this memorandum as “fall-out issues” associated with Issues 4A and 4B.
[2]The Florida Retail Federation (FRF) filed a notice of joinder in OPC’s brief on the same date.

Discussion of Issues

Issue 1D: Is it in the consumers' best interest for the utilities to continue natural gas financial hedging activities?

Recommendation: Yes. Staff recommends that continuation of fuel price hedging activities is in the consumers' best interest. (Lester, Barrett)

Position of the Parties

FPL: Yes. Utilities' natural gas financial hedging programs have worked exactly as intended by the Commission and the utilities to limit the volatility of fuel costs that FPL customers pay. The intervenors have failed to demonstrate that the program should be revised or discontinued.

DEF: As part of effective fuel cost management, DEF believes managing fuel price volatility risk over time for a portion of its projected fuel costs is a prudent risk management practice. However, this is a policy decision for the Commission to determine.

FPUC: No position.

GULF: Yes. Future market price risk and price volatility still exists for natural gas purchases. Changes in the natural gas market have occurred and will continue to occur in the future as gas producers and consumers adapt to both regulatory and market price pressures and uncertainty. Order No. PSC-08-0667-PAA-EI provides the utilities an appropriate fuel risk management tool for use in limiting future natural gas price volatility and should be continued going forward. Gulf has demonstrated that implementation of its risk management plan has accomplished the objective of the hedging order to limit price volatility.

TECO: Yes. These hedging programs have worked exactly as intended by the Commission and the utilities by eliminating the volatility of fuel costs that utility customers have to pay. The Intervenors have failed to demonstrate that these programs should be revised or discontinued. Future natural gas market price risk and price volatility remain for natural gas purchases. However, should the Commission conclude that the programs should cease, it should occur prospectively, with existing hedges remaining in place to their maturities. Any cessation should remain in place until such time as the Commission orders approval of new risk management plans.

OPC: No. The facts and evidence adduced at the fuel clause hearing unequivocally demonstrate that it is not in the best interest of the customers for the Companies to continue natural gas financial hedging activities. Hedging is a net cost unnecessarily added to the price of fuel. Any perceived benefits received from hedging are vastly outweighed by the billions of dollars in costs paid by customers for this temporary benefit.

FIPUG: No. Hedging should be discontinued.

FRF: Adopts the position of OPC.

PCS Phosphate: No. PCS agrees with the Office of Public Counsel. For the facts and reasons described in the testimonies of OPC witnesses Noriega and Lawton and in OPC's basic position, it is not in the best interest of the customers for the Companies to continue natural gas financial hedging activities.

Staff Analysis: Staff will begin its analysis of this issue by providing a background on how the Commission's policy on hedging has developed, and key actions the Commission has taken regarding the hedging programs that Florida's four largest IOUs use today. Thereafter, staff's consideration of this issue will address the key arguments the witnesses addressed, followed by staff's analysis and conclusions.

Background

Financial hedging is the use of swap contracts and options to fix the price at the time the hedge instrument is executed for fuel to be delivered at a future date. Physical hedging is the use of long-term fixed price contracts with suppliers to fix the price of fuel over a period. Hedging allows utilities to manage the risk of volatile swings in the price of fuel. Prior to 2001, IOUs had carried out a small number of financial hedging transactions. In response to significant fluctuations in the price of natural gas and fuel oil during 2000 and 2001, the Commission raised issues regarding the utilities' management of fuel price risk as part of the 2001 fuel clause proceeding. The specific issues raised involved the reasonableness of hedging as a tool to manage fuel price risk and the appropriate regulatory treatment of hedging gains and losses. These issues were spun off to Docket No. 011605-EI for further investigation.

At the hearing for Docket No. 011605-EI, parties reached a settlement of all issues. By Order No. PSC-02-1484-FOF-EI ("Hedging Order"),[3] the Commission approved the settlement of the issues. Specifically, the settlement provided a framework that incorporated hedging activities into fuel procurement activities. For natural gas, fuel oil, and purchased power, the settlement allowed Florida's generating IOUs to charge prudently incurred hedging gains and losses to the fuel clause. The Hedging Order specified that the Commission will review each IOU's hedging activities as part of the annual fuel proceeding.

The Hedging Order required utilities to file risk management plans as part of true-up filings. The intent of this requirement was to allow the Commission and parties to the fuel docket to monitor utility hedging activities. As part of the annual final true-up filings in the fuel docket, utilities were required to state the volumes of fuel hedged, the type of hedging instruments, the average length of the term of the hedge positions, and fees associated with hedging transactions.

Although the Hedging Order allowed utilities flexibility in the development of risk management plans, the order also set forth guidelines utilities were to follow. For example, the order required that risk management plans identify the objectives of the hedging programs and the minimum quantities to be hedged. The order also required that plans provide mechanisms and controls for the proper oversight within the utility of hedging activities, as well as include the method for assessing and monitoring fuel price risk.

[3]Order No. PSC-02-1484-FOF-EI, issued October 30, 2002, in Docket No. 011605-EI, *In re: Review of investor-owned electric utilities' risk management policies and procedures.*

In tandem with Docket No. 011605-EI, staff conducted a review of Internal Controls of Florida's Investor-Owned Utilities for Fuel and Wholesale Energy Transactions. This study examined the practices, procedures, controls, and policies these companies followed when purchasing fossil fuels and wholesale energy. The study period looked at data from 1998 through 2001. The study concluded that Florida IOUs had engaged in physical hedging in fuel procurement but very limited financial hedging. At the time, the IOUs had not set up the proper controls to engage in extensive financial hedging. Also, for the period studied, TECO and Gulf had little exposure to the volatility of natural gas prices.

The next time the Commission reviewed its policy on hedging was at the 2007 fuel hearing. Parties raised questions regarding the period for which the Commission was determining the prudent costs of hedging activities. The Commission deferred its decision on the prudence of 2007 hedging activity costs to 2008 in order to allow for sufficient detail and review of the matter.

Following the 2007 fuel hearing, staff initiated two audits of the IOUs hedging programs. Staff conducted a management audit that reviewed IOUs hedging programs to assess the costs and benefits realized since the Hedging Order. Staff also reviewed the IOUs accounting treatment of 2007 hedging activities to determine compliance with risk management plans filed in 2006.

The management audit assessed the current and historical strategies of the fuel procurement hedging programs within each company at that time, evaluated hedging objectives set forth in each company's risk management plan, and quantified the net costs and benefits of each company's hedging program. Specifically, staff examined the structure and performance of hedging natural gas and fuel oil through the use of physical purchases and/or financial instruments for the years 2003 through 2007. Staff collected information from each company's policies and procedures, organizational charts, risk management plans, and historical hedging transactions, and provided an analysis for each company. In June 2008, Commission staff issued a report entitled Fuel Procurement Hedging Practices of Florida's Investor-Owned Electric Utilities.

In its 2008 report, staff found that each company shared a universal goal in purchasing financial hedges for its fuel procurement; that is, to reduce the impacts of the price extremes that can occur in the natural gas and fuel markets. In their hedging activities, the companies were not attempting to speculate on price movements in the market. Rather each was working to stabilize its annual fuel costs by initializing and settling financial hedging transactions through authorized financial counterparties. The volumes of gas and fuel oil hedged would be less than the total volumes expected to be purchased. Overall, staff believed that the use of financial hedges for fuel purchases provided a benefit to utility customers.

In response to the deferral of the determination of the prudent costs in the 2007 fuel hearing, on January 31, 2008, FPL filed a petition requesting that the Commission approve FPL's proposed volatility mitigation mechanism (VMM) as an alternative to FPL's hedging program. The VMM proposal involved FPL collecting under recoveries of fuel costs over two years instead of one year, as is the current practice. On March 11, 2008, staff held a workshop to get stakeholder input on this proposal. All parties to the 2002 settlement attended.

By Order No. PSC-08-0316-PAA-EI,[4] the Commission clarified the Hedging Order in several areas. IOUs were required to file a Hedging Information Report by August 15th of each year. The Commission also specified that it would make a determination of prudence of hedging results for the twelve month period ending July 31st of the current year. Staff held additional workshops on June 9, 2008 and June 24, 2008, regarding FPL's VMM petition and guidelines for hedging programs. FPL withdrew its VMM petition on August 5, 2008.

Following the workshops, the Commission established guidelines for risk management plans by Order No. PSC-08-0667-PAA-EI.[5] The Commission noted that its approval of the proposed guidelines demonstrates the Commission's support for hedging. The Commission also determined that utility hedging programs provide benefits to customers. The guidelines clarified the timing and content of regulatory filings for hedging activities, but allowed the IOUs flexibility in creating and implementing risk management plans. Each year in the fuel clause, staff auditors review utility hedging results for the twelve month period ending July 31 of the current year. In addition, each year the Commission approves the IOUs' risk management plans for hedging transactions the utility will enter the following year and beyond.

No other hedging-related orders have been issued to-date, although on various dates since the issuance of these three orders, staff has presented hedging-related information to the Commission at Internal Affairs meetings.

Since the 1990s, natural gas-fired generation has become a large part of the generation mix for Florida IOUs, and the increasing role for natural gas is expected to continue. Natural gas prices have been volatile over the years, with significant price spikes in 2000, 2003, 2005, and 2008. Since 2008, natural gas supply has increased significantly due to shale gas production.

Arguments

In direct testimony, FPL witness Yupp stated the objective of FPL's fuel price hedging is to reduce price volatility. He stated FPL does not engage in speculation and that FPL carries out its program consistent with its approved risk management plan. (TR 377-378, 398-400) Witness Yupp noted that fuel price hedging is important for FPL and its customers because FPL projects that 72 percent of the electricity it produces in 2016 will be generated with natural gas. (TR 399, 410) He further noted that hedging is not intended to reduce fuel costs. Rather, hedging is a tool to reduce the volatility of fuel rates. (TR 400) Since FPL hedges only a portion of its projected natural gas consumption, customers can benefit from falling prices affecting the unhedged portion. (TR 400-401)

In direct testimony, DEF witness McCallister stated that DEF has a structured approach to hedging, and that there are two primary objectives that DEF's hedging program seeks to achieve:

- To reduce the impacts of fuel price volatility over time.
- To provide a greater degree of fuel price certainty to its customers.

[4]Order No. PSC-08-0316-PAA-EI, issued May 14, 2008, in Docket No. 080001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor*.
[5]Order No. PSC-08-0667-PAA-EI, issued October 8, 2008, in Docket No. 080001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance inventive factor*.

(TR 465, 470, 477; EXH 116) The witness stated that DEF's hedging program targets purchasing a certain percentage of natural gas over time whether prices are high or low, which he believes is a prudent risk management practice. (TR 477, 1008, 1010; EXH 116; DEF BR 1) Additionally, the witness stated that DEF's program is executed in an environment of strong internal controls, in a non-speculative, structured manner. (TR 467, 477, 497) Furthermore, by following its Commission-approved Risk Management Plans in a non-speculative manner, DEF is not trying to "out-guess" the market in order to meet its objectives. (TR 467, 471-472; EXH 116) When cross-examined by the OPC, the witness acknowledged that the results of DEF's hedging activities for natural gas from 2002 through 2014 was a hedging loss of about $1.2 billion, and further losses were projected for 2015. (TR 475, 499) Additionally, witness McCallister stated that by executing hedges on a regular, non-speculative manner, the company is executing hedges in different market environments over time as those markets change. (TR 478) In doing so, DEF is not estimating or forecasting whether hedging gains and losses will occur, according to witness McCallister. (TR 467; EXH 116) He acknowledged that DEF does not forecast the volatility of natural gas, and also that DEF's fuel mix is a consideration in setting fuel hedging target ranges, and noted DEF's projected fuel mix for 2016 is approximately 73 percent natural gas. (TR 476, 486, 492, 1008; EXH 116)

Witness McCallister stated that customer interests are very important in this process and that the Commission should be cognizant of this. (TR 507) He noted that the Commission's hedging program acts to serve customer interests, and not the interests of utilities. (TR 1009) He expressed ambivalence about continuing hedging if the Commission or its customers wanted to stop hedging. (TR 489-491, 1010; DEF BR 2) He cautioned, however, that without a hedging program, customers would have no protection against price swings, and could be subject to large under and over recoveries, or mid-course corrections. (TR 510)

Gulf witness Ball asserted that the objective of natural gas hedging is to "reduce the upside price risk to Gulf's customers in a volatile price market." (TR 653; Gulf BR 2, 4, 8) The witness elaborated as follows:

> We do not look at gains and losses. We look at standard deviation of pricing, both hedged and unhedged, and we determine in each case that the volatility or the standard deviation of the hedged pricing for the year is lower than the standard deviation of the unhedged prices, thus basically making the case that we have reduced the volatility of pricing.

(TR 696)

He stated that Gulf's hedging program provides price stability to customers and is a protection against unanticipated dramatic price increases in the natural gas market. (TR 680; EXH 117; BR 2) Witness Ball acknowledged, however, that natural gas market conditions are far different in 2015 than in the era when hedging began. (TR 687) He also stated that weather events are "a significant driver of natural gas demand, and, as a result, natural gas prices." (TR 688; Gulf BR 5) Nonetheless, he states that Gulf has followed its Risk Management Plan for hedging, and over the long term, his Company anticipates less volatile future fuel costs because its hedging program has been utilized. (TR 669-670, 698; EXH 117; Gulf BR 3, 8) When asked about what

Gulf's customers would face without hedging, witness Ball stated that customers would bear the full market prices with no measure of protection from price spikes, and possibly mid-course corrections due to swings in over and under recovery balances. (TR 707-708)

In direct testimony, witness Caldwell stated that TECO follows a non-speculative risk management strategy to reduce fuel price volatility and to maintain a reliable supply of fuel. TECO had hedging savings for 2014. Shale gas production increased supply and decreased prices after a sharp increase in early 2014. Fuel savings may or may not result from hedging activities. TECO's hedging program follows a disciplined approach and does not attempt to out-guess the market. (TR 722-723, 752-754; EXH 118) Witness Caldwell noted that Florida IOUs have been employing a hedging strategy since 2002 when the Commission issued an order addressing fuel price hedging. In 2008, the Commission issued guidelines for hedging programs and found that these programs provide customer benefits by mitigating price volatility. (TR 756-759)

OPC witness Noriega testified as a fact witness for OPC, presenting testimony and exhibits that summarize the results of the hedging programs since 2002. (TR786, 790, 807; EXH 54, EXH 55) Based on the most current information available, the witness stated that natural gas hedging programs have lost approximately $5.3 billion over the time period from 2002-2014, with additional losses projected for 2015.

Table 1D-1
Results of Natural Gas Hedging[6]

Year	DUKE	GULF	TECO	FPL	TOTALS
2002-2014	($1,267,848,634)	($127,278,227)	($381,417,733)	($3,516,671,769)	($5,293,216,363)
Est. 2015	($215,000,000)	($44,000,000)	($40,000,000)	($490,000,000)	($789,000,000)
TOTAL	($1,482,848,634)	($171,278,227)	($421,417,733)	($4,006,671,769)	($6,082,216,363)

Source: TR 416, 475, 686, 761; EXHs 54, 55, 105; OPC BR 32

OPC witness Lawton stated hedging programs have two types of costs: the costs of running the program (typically not large) and the opportunity costs and benefits of hedging depending on how the market prices settle compared to the hedged price. (TR 827) Using results provided by OPC witness Noriega, witness Lawton noted hedging opportunity costs, also described as hedging losses, during the period 2009 through 2014 have been large. (TR 823, 831) According to witness Lawton, customers are insulated from daily price swings in the price of natural gas because the fuel factors are set annually. The cumulative effect of price swings could result in a mid-course correction to fuel factors. (TR 828-829) Witness Lawton believed the hedging losses since 2008 should bring continuation of fuel price hedging in Florida into question and notes that losses have not offset gains. (TR 830) Witness Lawton stated that natural gas prices and price volatility have been declining. Price volatility can be measured by the standard deviation of daily, monthly, and annual prices. (TR 835)

[6]In its brief, OPC filed proposed findings of fact with regard to the natural gas hedging cumulative net losses and gains for each IOU for the years 2002-2014, natural gas hedging actual and projected net losses and gains for 2015, and the combined natural gas hedging historical and projected cumulative net losses and gains for the years 2002-2015. (OPC BR at 32) To the extent not reflected in this table, OPC's proposed findings of fact are not adopted.

Witness Lawton stated that Florida IOUs hedge significant portions of their projected natural gas burn. (TR 835-836) He noted that the IOU's hedging programs are designed to reduce the variability or volatility of fuel prices and not necessarily fuel cost. (TR 837) Florida IOU hedging programs accomplish the goal of limiting price volatility. The IOUs hedge less than 100 percent of their projected gas burn. The programs are non-speculative and avoid market timing. Witness Lawton believes that Florida IOUs should reconsider their hedging programs in light of declining volatility, increased production and reserve levels, and forecasted lower prices. (TR 840-842)

Witness Lawton testified that natural gas price volatility has declined over the period 1997 through 2015. (TR 848-850) Looking at daily price movements, there are fewer days where the price change exceeds levels from $0.25 to $1.00. The size and frequency of price changes are lower, according to witness Lawton. (TR 853-855) However, he noted that historical price and volatility trends may not be a predictor of future trends. (TR 856)

Witness Lawton noted that natural gas reserves have increased. The Energy Information Administration (EIA) 2015 long term forecast presents increased supply and lower natural gas prices compared to the 2011 long-term forecast. (TR 858-859) Witness Lawton believes the forecasts of increased supply and slower growth in prices suggest declining price volatility. (TR 860-861)

The Commission reviewed hedging in a workshop in 2011, and no changes were made to hedging programs. (TR 862-863) Witness Lawton stated that several states have discontinued natural gas price hedging or do not allow hedging (TR 863-868) Noting EIA long-term forecasts regarding supply and price trends, he believes the natural gas markets have changed substantially and will experience lower price volatility. (TR 868)

Witness Lawton reviewed the VMM alternative to hedging that was presented by FPL in 2008. While he does not endorse the alternative, it does provide a longer period for recovering fuel cost under-recoveries. Witness Lawton concluded that natural gas markets have changed substantially since 2002 and recommended that financial hedging of natural gas prices be discontinued and that the Commission not approve the IOUs risk management plans. (TR 871-872)

In rebuttal to OPC witness Lawton, FPL witness Yupp stated that the primary purpose of hedging is to reduce price volatility. Rising prices will provide savings for customers and falling prices will incur costs. (TR 938-939) Hedging has significantly reduced the number of times FPL was outside of the 10 percent mid-course correction threshold, according to witness Yupp. (TR 940; EXH 106) Witness Yupp believed the success of FPL's hedging program should not be based on gains or losses as this would involve speculation about the direction of the market. Instead, hedging is about mitigating volatility. (TR 940-941) He noted that a hedging program should be well disciplined to avoid speculation. To discontinue the hedging program with the thought of starting it back up in the future would amount to "chasing the market." (TR 941-942)

Witness Yupp disagreed with witness Lawton's calculation of price volatility in natural gas markets from 1997 to 2015. He provided his version of the calculation and finds price volatility to be much higher, notably in 2014. (TR 943-944; EXH 57, EXH 107)

Witness Yupp agreed with witness Lawton regarding a general trend toward lower average annual volatility but he notes some large year to year swings. He noted that price volatility varies significantly year to year and cannot be reliably predicted. (TR 946-947). He further testified that volatility of natural gas prices is high relative to other traded commodities such as crude oil and relative to the volatility of the S&P 500. (TR 948-949; EXH 109)

Witness Yupp noted that prices cannot go below the variable cost of production for any extended period. He believed there are asymmetrical risks associated with price movement. Given the current relatively low natural gas prices, the direction of prices is more likely to move up than further down, making it an inappropriate time to discontinue hedging. (TR 947-949; EXH 108)

In his rebuttal testimony, DEF witness McCallister stated that DEF has no basis to disagree with OPC Lawton's belief that future natural gas prices will be stable with declining volatility, although he warned that Florida's pronounced reliance on natural gas to fuel generating plants will expose ratepayers to market swings that could be more impactful to customers if today's hedging programs are removed. (TR 1006, 1014-1016; EXH 116) He restated that DEF's projected fuel mix for 2016 is approximately 73 percent natural gas. (TR 1008) Witness McCallister added that the hedging programs are intended to serve consumer interests, and not those of the utilities that participate in the programs, and concluded by noting that he agreed with OPC witness Lawton that the Commission should periodically review its hedging policies. (TR 1006; EXH 116)

In rebuttal, Gulf's witness Ball asserted that OPC witness Lawton failed to discuss that a number of factors could impact natural gas supply and demand. (TR 1030; Gulf BR 2) He believes increased future demand in the market for natural gas could lead to increased volatility, and that existing or proposed environmental regulations could impact shale gas production, as well as decisions regarding generating mixes for utilities. (TR 1029-1030; Gulf BR 5) Although OPC presented evidence that lifetime hedging costs have outpaced hedging gains, witness Ball stated "historical data is not a reliable predictor of future events and, in this case, is not reliable evidence of the absence of future gas price volatility." (EXH 117; TR 1030) The witness believes that future price risk and price volatility still exist, and the company's risk strategy, as set forth in its Risk Management Plan is appropriate. (TR 1035; EXH 117; Gulf BR 8)

In rebuttal to OPC witness Lawton, TECO witness Caldwell opined that, if natural gas prices were rising and fuel price hedging programs were producing savings, the intervenors would not be challenging hedging. He noted that customers benefit from the decline in natural gas prices for the unhedged portions of gas consumption. (TR 1054) As part of reducing price volatility, hedging can result in lost opportunity costs when price declines below the hedged price. (TR 1055-1056)

Witness Caldwell also noted that the current abundance of shale gas may not continue to contribute to lower price trends. He reviewed the history of gas supply and prices and noted earlier periods – with offshore gas and with liquefied natural gas – when prices recovered after a period of adjustment. (TR 1056) The generation mix in Florida and nationally is moving toward more natural gas, with the replacement of coal-fired units and the aging nuclear fleet. According to the witness, natural gas is essential during periods of high demand or supply constraint. (TR 1057)

Witness Caldwell noted that the standard deviation of market gas prices is significantly above that of hedged prices. This proves that hedging has reduced the customer's exposure to price volatility. (TR 1058) He further noted that the volatility in annual fuel cost recovery factors is reduced. According to witness Caldwell, a levelized fuel factor does not mitigate price volatility. He noted that the variance from forecasted fuel costs is reduced with hedging, thus reducing true-up amounts. (TR 1060)

Analysis

This issue focuses on three, somewhat overlapping arguments: (1) the significant opportunity costs of hedging programs that IOUs incurred as part of fuel costs paid by customers; (2) whether the volatility of natural gas prices has declined to the point where hedging is no longer effective or necessary; and (3) whether conditions in the natural gas market are stable and eliminate the need for hedging.

Opportunity Costs and Savings

In their briefs, the intervenors argued that hedging should be discontinued due to the large cumulative net losses.[7] (OPC BR 3, 7-8; PCS BR 1, 4; FIPUG BR 4) In their brief, the IOUs state the purpose of hedging is to reduce price volatility, that gains and losses can occur, and that assessing the hedging programs based on gains and losses would encourage speculation. (FPL BR 8; Gulf BR 2-3; TECO BR 5)

The IOU witnesses acknowledged significant net cumulative hedging losses for natural gas. FPL had losses of $3.5 billion for the period 2002 to 2014 for natural gas ($3.162 billion when fuel oil hedging gains are included) and $490 million for 2015. (TR 415-416) DEF incurred $1.2 billion in losses for the period 2002 to 2014 and estimates $196 million in losses for 2015. (TR 474-475) Gulf Power incurred $127 million in losses from 2002 to 2014 and estimates $44 million for 2015. (TR 686) Tampa Electric incurred losses of $381 million for the period 2002 to 2014 and estimates $40 million for 2015. (TR 761) FPL's recently approved Woodford project is estimated to experience hedging losses for 2015. (TR 423-24) OPC witness Lawton notes that prolonged periods of losses should signal a re-evaluation of hedging programs. (TR 830; also EXH 121)

There have been earlier periods before 2008 when gains offset losses. (TR 975-977; EXHs 55, 115, 116, 117, 118) Customers also benefit from falling prices for the unhedged portion of the gas supply portfolio. (TR 439-440, 768)

The IOU witnesses stated that the goal of their hedging program is to reduce volatility. (TR 938-939, 1008, 1028, 1055-1056, 1058-1059) Witness Yupp noted that gains and losses should not be used to judge the success of the program and that the Commission-approved hedging guidelines provide reasonable tradeoffs for mitigating volatility. (TR 442-443, 975)

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[7]The Florida Retail Federation filed a Notice of Joinder in the Citizens Post-Hearing Statement of Positions and Post-Hearing Brief.

Staff believes the level of opportunity savings and costs – hedging gains and losses – should not be a chief consideration in deciding whether to continue fuel price hedging. When gas prices are falling, losses will occur. Conversely, when gas prices are rising, gains will occur. The main objective of IOU hedging programs is to reduce the customer's exposure to fuel price volatility, not to reduce fuel costs. Therefore, these programs should be well disciplined to accomplish this objective and to be non-speculative.

As emphasized by intervenors, the cumulative losses are currently large. These losses took place in an environment of steadily falling natural gas prices. Customers experienced the benefits of this downward trend in prices for the unhedged portions of the IOU natural gas purchases. Should natural gas prices trend or spike upward, hedging savings will occur but, overall, fuel costs will increase.

Natural Gas Price Volatility

OPC witness Lawton argued that price volatility has decreased, making hedging unnecessary. (TR 835, 848-850) The IOUs do not forecast price volatility. (TR 417, 476) While FPL witness Yupp does not agree that price volatility is trending downward, DEF witness McAllister agreed that prices are less volatile. (TR 417-418, 476) Gulf witness Ball stated that Gulf does not forecast price volatility and suggests such a forecast is not possible. He notes – with exceptions – that in recent history volatility is lower. (TR 688-689) Witness Caldwell agreed that fuel price volatility decreased during the period 1997 to 2015. (TR 763)

Witness Yupp disagreed that the volatility of natural gas prices is currently decreasing. (TR 417) He provided an exhibit showing that the volatility of natural gas prices varies considerably year to year. The trend line for this volatility shows a decline but there is very low correlation for the yearly data. The trend line in price volatility is not a good predictor of the next price volatility point. (TR 943-946, 953, 969-971; EXH 107, EXH 130)

Witness Yupp provided evidence that hedging has reduced the number of times FPL was outside of the 10 percent mid-course correction threshold. (TR 939-940, EXH 106) He acknowledges that both under-recoveries and over-recoveries of fuel costs occurred. (TR 962-963)

Witness Lawton acknowledged that current EIA forecasts for natural gas prices show a confidence interval ranging more toward higher prices than lower prices. (TR 888-890; EXH 126) Witnesses Ball affirmed this aspect of the forecast as well. (TR 1031)

In its brief, OPC argued that the annual fuel factor smoothes out price volatility and is a cost-free alternative to hedging. (OPC BR 11, see also PCS BR 4) Witness Lawton stated that the annual or level fuel factor shields customers from day-to-day changes in market prices. He acknowledges the cumulative effect of unexpected changes in market prices could lead to a mid-course correction to fuel factors. (TR 828-829) Witness McAllister agreed that the level fuel factor can reduce the customer's exposure to price volatility within the year, assuming no mid-course correction. However, without hedging, the true-up amounts can be significant. (TR 509-510) Witness Caldwell testified that, while the annual fuel factor provides some smoothing over twelve months, it does not limit the potential for fuel costs to increase or decrease. Hedging can limit potential changes in fuel costs and mitigates price and fuel factor volatility. (TR 1058-1060) Spreading an under-recovery over more time presents a risk of stacking under-recoveries if prices rise. (TR 1067-1068)

The level or annual factor has some smoothing effect within the year assuming no mid-course corrections. By providing certainty to a portion of expected gas consumption, hedging can reduce true-up amounts and mid-course corrections. Without hedging, large true-up amounts and deferrals could occur.

All witnesses generally agree that price volatility cannot be accurately and consistently forecasted. Staff concludes that price volatility varies up and down significantly and that it cannot be forecasted. Therefore, while natural gas prices have trended downward in the last few years, the level of price volatility is uncertain. Witness Yupp noted that a one cent change in natural gas prices translates to $6 million for FPL. (TR 981-982) Further, the increased dependence on natural gas means customers would have significant exposure to the uncertainties of natural gas prices if hedging were discontinued.

The objective of the IOUs' hedging programs is to reduce the customers' exposure to price volatility. Staff concludes that, while natural gas prices have recently trended downward, the volatility of those prices can vary considerably and can have a significant effect on the IOUs' total fuel cost.

Currently, natural gas prices are low compared to prices since 2008. One could reasonably assume that prices are more likely to rise than to continue downward, and FPL witness Yupp provides calculations, reasons, and an opinion supporting this possibility. That prices may be approaching or going below the variable cost of production is a noteworthy consideration. However, staff believes the low prices and possible price direction should not be a chief consideration since it would involve some degree of speculation about the future direction of prices.

Natural Gas Market Conditions

Intertwined with price volatility are the supply and demand conditions of the natural gas market. All witnesses agreed that natural gas market conditions in 2015 are different from those of 2002. All witnesses agreed that the growth of shale gas production has increased the supply of natural gas. (TR 416-417, 475, 687, 958) Witness Caldwell notes that the natural gas market seems to move in cycles of significant production increases, due to new sources, followed by increases in demand (TR 762, 1056)

Natural gas prices are more volatile when weather events affect supply or demand. In January 2014, the polar vortex had a significant effect on natural gas prices. (TR 688, 848, 883) Weather events, such as very cold periods during the winter, can increase demand, prices, and volatility. (TR 883-884, 953) Additional pipelines under construction that connect the Marcellus Shale to northeastern states may diminish this effect. (TR 884)

Regarding shale gas production and the current abundant supply of natural gas, witness Yupp noted that the market price may be below the cost of production for many producers. The market price cannot be below the cost of production for any extended period of time. He further noted that production costs vary among producers. (TR 421-422) Rig counts are down and this could impact gas supply but this may not be a complete indicator of future gas production. (TR 882; EXHs 81, 88, 96, 102) Witness Ball alluded to future events that could disrupt shale gas production. (TR 1029-1031) As noted above, witness Lawton testified to increases in gas reserves, suggesting an adequate supply for the future. (TR 857)

In its brief, OPC minimized the potential threats to shale gas production. (OPC BR 12) Witness Lawton opined that environmental concerns have largely been put to rest. He acknowledged that New York currently bans fracking. (TR 908-909) Staff notes there are specific risks associated with shale gas production. (TR 769, 1029; EXHs 81, 88, 96, 102) These risks include more Federal and State regulations for hydraulic fracturing, which is used for shale gas production.

Demand for natural gas, particularly for electric generation, is increasing. In Florida, natural gas represents a significant percentage of the fuel for generation and this dependence on natural gas is increasing. In 2016, DEF estimates 73 percent of its generation will be from natural gas. FPL estimates 72 percent. For Tampa Electric and Gulf, the figures are 52 percent and 44 percent, respectively. (TR 489, 677, 734, 772, 901, 981, 1008, 1057; EXHs 12-14, 24, 42, 47) In addition, natural gas will begin to be exported in late 2015 and a number of export terminals are under construction or are planned. (TR 383-384, 486-486; EXHs 81, 88, 96, 102)

Conclusion

Staff believes the decision of whether to continue fuel price hedging rests with what one expects price volatility and natural gas market conditions to do in the future. Staff believes, while natural gas prices have trended down, price volatility is uncertain and cannot be reliably forecasted. What is known is that, without hedging, customers have very significant exposure to natural gas price volatility.

Regarding market conditions, the natural gas market is very dynamic. While prices have trended lower and gas supply is currently forecasted to be abundant, demand is increasing and is heavily influenced by weather and potentially uncertain supply conditions.

As such, staff believes that continuation of fuel price hedging activities is in the consumers’ best interest.

Issue 1E: What changes, if any, should be made to the manner in which electric utilities conduct their natural gas financial hedging activities?

Recommendation: No changes are warranted at this time to the manner in which electric utilities conduct their natural gas financial hedging activities. (Barrett)

Position of the Parties

FPL: No changes should be made to the manner in which electric utilities currently conduct their natural gas financial hedging activities.

DEF: This is a policy decision for the Commission. If the Commission determines that hedging should be wound down and eliminated, reduced in scope, suspended, or replaced with something new, DEF will comply with the Commission's policy.

FPUC: No position.

GULF: None. As noted in response to Issue 1D, Gulf believes that it is appropriate to continue its financial hedging activities as an appropriate risk management tool. Gulf has demonstrated that implementation of its risk management plan has accomplished the objective of the hedging order to limit price volatility. No changes are necessary or appropriate at this time.

TECO: There should not be any changes to the manner in which electric utilities conduct their natural gas financial hedging. No such changes have been proposed in this proceeding. Moreover, the current natural gas financial hedging model was carefully constructed after due consideration of all relevant matters by the Commission and all affected persons. No changes are in order.

OPC: The natural gas financial hedging activities of the Companies should be discontinued. The facts and the evidence adduced at the fuel clause hearing unequivocally demonstrate that the Commission should deny the Companies' Risk Management Plans as they relate to natural gas financial hedging activities and the Commission should suspend and end the practice of natural gas financial hedging.

FIPUG: Hedging should be discontinued.

FRF: Adopts the position of OPC.

PCS Phosphate: PCS agrees with the Office of Public Counsel. For the reasons described in the testimonies of OPC witnesses Noriega and Lawton and in OPC's basic position, the Commission should deny the Company's risk management plans as it relates to natural gas financial hedging activities and should suspend and end the practice of natural gas financial hedging.

Staff Analysis: Staff notes this issue is essentially a fallout consideration of Issue 1D. In order to minimize duplicative arguments and for administrative efficiency, the argument for this issue will be brief.

Arguments

As presented in Issue 1D, the parties that participate in hedging activities believe that hedging is in the public interest and should be continued. (FPL BR 2, 15; DEF BR 1; Gulf BR 3, 7; TECO BR 5) As a fallout to that decision, those parties answer to this issue reflects a position that no changes are needed to the manner in which electric utilities currently conduct their natural gas financial hedging activities.

FPL witness Yupp states that no changes are needed because his company's hedging program has "worked exactly as intended by the Commission and FPL to limit the volatility of fuel costs that FPL's customers pay." (TR 951; BR 6) Because the future is uncertain and volatility still exists, FPL's witness believes hedging should continue. (TR 978, 980) DEF's witness McCallister stated that DEF is open to continuing in the current recovery practices, or something new, but stated that the timing aspects of fuel cost recovery is something the Commission should be aware of. (TR 1022; FPL BR 2)

OPC's case advocated that hedging be eliminated prospectively, and the intervening parties by and large supported this position. (OPC BR 1; PCS BR 1; FIPUG BR 1) Staff believes that if OPC's basic position in Issue 1D to completely eliminate hedging on a prospective basis prevails, answering this issue is unnecessary.

Analysis

Consistent with staff's recommendation in Issue 1D, staff believes natural gas hedging activities are in consumers' best interest, and should continue prospectively. Staff believes no changes are warranted at this time to the manner in which electric utilities conduct their natural gas financial hedging activities.

However, if the Commission wants to consider changes that could be made to the manner in which electric utilities conduct their natural gas financial hedging activities a subsequent proceeding can be scheduled. A few options that were identified are described below:

Alternative Accounting Treatment of Hedging Gains/Costs

At the present time, hedging gains/losses are recognized and reported at the time they occur. In practice, if the results of hedging activity for a given month resulted in a hedging gain, the amount of that gain is reflected as an offset to the fuel costs for that period. Conversely, if the results of hedging activity for a given month resulted in a hedging loss, the amount of that loss is reflected as an adder to the fuel costs for that period.

An alternative treatment of hedging gains/losses would be to defer the timely recovery (of a hedging gain or a hedging cost) to a future period. A future period could be defined as a month, a quarter of a year, or even a year or longer. An advantage for doing so would be that ratepayers would be somewhat shielded from volatile hedging results. A disadvantage would be that any deferral of costs might artificially create a lump sum swing in fuel costs if the deferral was for an extended period.

Although no party advocated that an alternative accounting treatment of a hedging gains/costs was needed, staff notes that several witnesses referred to FPL's Volatility Mitigation Mechanism (VMM) proposal, which was only a mitigation proposal to spread hedging costs over a 2 year period. FPL witness Yupp stated that FPL's VMM proposal was offered at a time when there was regulatory uncertainty around hedging, and was withdrawn when the hedging guidelines were developed. Additionally, the witness stated that VMM did not mitigate price spikes to consumers. (TR 989-990)

DEF witness McCallister stated that FPL's VMM was evaluated years ago, but offered that his company would have to study an alternative like that in order to offer a definitive opinion on it. (TR 1022) Witness Ball from Gulf echoed the same concern, acknowledging that a year over year under-recovery would be amplified, if an alternative accounting treatment required that a balance be carried over. (TR 1049) The "stacking effect" is a real consideration, according to TECO witness Caldwell, and for this reason, his company would not support an alternative accounting treatment that required a balance be carried over in this manner. (TR 1059) Witness McCallister stated that a deferred recovery only addresses the timing of the recovery, not volatility. (TR 1023).

Impose Limits on the Upper Range of Hedging Volumes

At the present time, the IOUs hedge natural gas according to the range of volumes set forth in their risk management plans. Generally, the upper and lower hedging limits are company-specific and confidential, and are expressed as a percentage of total natural gas burn.

The Commission could consider imposing a "not to exceed" threshold to limit the upper range of volume to be hedged. An advantage of doing this would be to limit hedging losses in periods when market prices were lower than hedged prices. However, the disadvantage for imposing an upper limit on hedged volumes would be that hedging gains would be limited in times when hedged prices would be lower than market prices.

Implement a Sharing Mechanism

At the present time, all hedging gains and costs are borne by customers. An advantage of implementing a sharing mechanism would be to limit hedging losses for customers in periods when market prices were lower than hedged prices. However, the disadvantage for imposing a sharing mechanism would be that participants might speculate on future prices as a means to mitigate to their shared exposure, which would be contrary to the principles and guidelines expressed in the 2002 and 2008 hedging orders.

At the hearing, hedging witnesses were asked their opinion of implementing a mechanism whereby gains and costs could be shared between the company and ratepayers. DEF witness McCallister stated that it might lead to speculation, and would not be something DEF would support. (TR 488) This thought was also expressed by TECO witness Caldwell while Gulf witness Ball opined that his company has no interest in such a proposal. (TR 1038, 1048, 1057)

Conclusion

Staff believes no changes are warranted at this time to the manner in which electric utilities conduct their natural gas financial hedging activities.

Issue 2B: Should the Commission approve DEF's 2016 Risk Management Plan?

Recommendation: Yes. The Commission should approve DEF's 2016 Risk Management Plan. (Barrett, Lester)

Position of the Parties

FPL: No position.

DEF: Yes, unless the Commission concludes that it is in the best interests of customers for the hedging program to be wound down and eliminated, reduced in scope, suspended, or replaced with something new. If the Commission amends or modifies the parameters of the hedging program, DEF will amend its Risk Management Plan accordingly, and will not execute any hedges beyond those previously executed per approved risk management plans to comply with the Commission's direction.

FPUC: No position.

GULF: No position.

TECO: No position.

OPC: No. The Risk Management Plan should not be approved as filed inasmuch as it would authorize the company to continue the financial hedging of natural gas. Incorporate by reference OPC's arguments for Issues 1D & 1E.

FIPUG: Hedging should be discontinued.

FRF: Adopts the position of OPC.

PCS Phosphate: No. PCS agrees with the Office of Public Counsel. The plan should not be approved as filed inasmuch as it would authorize the company to continue the financial hedging of natural gas.

Staff Analysis: Staff notes that the there is considerable overlap between the arguments DEF presented in Issue 1D and the issue to consider the approval of DEF's Risk Management Plan for 2016 (Issue 2B). In order to minimize duplicative arguments and for administrative efficiency, the argument for this issue will be brief and concise.

Arguments

Witness McCallister stated the hedging activities set forth in DEF's Risk Management Plan are followed in a structured manner to reduce price risk. (TR 497) Although small changes are made from year to year, DEF's prescriptive, consistent approach will be followed in 2016. (TR 514)

As presented in Issue 1D, OPC witness Lawton stated that prospective hedging activities should cease, and the Risk Management Plans for 2016 should not be approved. (TR 822)

Analysis

Consistent with staff's recommendation in Issue 1D that the utilities should continue natural gas financial hedging activities, staff recommends that the Commission approve DEF's 2016 Risk Management Plan. Staff believes DEF's Risk Management Plan for 2016 provides the appropriate governance for a well-disciplined and prudently-managed utility hedging program, and is consistent with the Hedging Guidelines.

Conclusion

Staff recommends the Commission approve DEF's 2016 Risk Management Plan.

Issue 3B: Should the Commission approve FPL's 2016 Risk Management Plan?

Recommendation: Yes. Staff recommends that the Commission approve FPL's 2016 Risk Management Plan.

Position of the Parties

FPL: Yes. On August 5, 2008, FPL filed a petition in the fuel docket requesting approval of Hedging Order Clarification Guidelines (the "Hedging Guidelines"). The Hedging Guidelines were approved by the Commission. Section I of the Hedging Guidelines provides for investor-owned utilities such as FPL to file a risk management plan covering the activities to be undertaken during the following calendar year for hedges applicable to subsequent years, and for the Commission to review such plans for approval as part of the annual fuel adjustment proceeding. FPL's 2016 Risk Management Plan is consistent with the Hedging Guidelines and should be approved.

DEF: No position.

FPUC: No position.

GULF: No position.

TECO: No position.

OPC: No. The Risk Management Plan should not be approved as filed inasmuch as it would authorize the company to continue the financial hedging of natural gas. Incorporate by reference OPC's arguments for Issues 1D & 1E.

FIPUG: Hedging should be discontinued. Otherwise, adopt the position of OPC.

FRF: Adopts the position of OPC.

PCS Phosphate: No position.

Staff Analysis: Staff notes that the there is considerable overlap between the arguments FPL presented in Issue 1D and the issue to consider the approval of FPL's Risk Management Plan for 2016 (Issue 3B). In order to minimize duplicative arguments and for administrative efficiency, the argument for this issue will be concise.

Arguments

From a historical perspective, witness Yupp believes that FPL's Risk Management Plan has reduced fuel price volatility, which delivered fuel price certainty for FPL's customers. (TR 398) The witness asserted that the Risk Management Plan for 2016 carries this forward by expressing the parameters within which FPL intends to place hedges during 2016. (TR 401) The witness noted, however, that the 2016 Plan differs from earlier plans because of FPL's participation in the Woodford Gas Reserves Project. (TR 402) FPL's hedging program is consistent with the guiding principles outlined in the Commission's hedging orders. (TR 399) FPL witness Yupp believes FPL's Risk Management Plan for 2016 should be approved.

As presented in Issue 1D, OPC witness Lawton stated that prospective hedging activities should cease, and the Risk Management Plans for 2016 should not be approved. (TR 822)

Analysis

Consistent with staff's recommendation in Issue 1D that the utilities should continue natural gas financial hedging activities, staff recommends that the Commission approve FPL's 2016 Risk Management Plan. Staff believes FPL's Risk Management Plan for 2016 provides the appropriate governance for a well-disciplined and prudently-managed utility hedging program, and is consistent with the Hedging Guidelines.

Conclusion

Staff recommends that the Commission approve FPL's 2016 Risk Management Plan.

Issue 3K: What costs are appropriate for FPL's Woodford natural gas exploration and production project for recovery through the Fuel Clause?

Recommendation: For the period January 2015 through December 2015, the appropriate actual/estimated costs FPL should recover through the Fuel Clause for the Woodford natural gas exploration and production project is $24,611,461. For the period January 2016 through December 2016, the appropriate projected costs FPL should recover through the Fuel Clause for the Woodford natural gas exploration and production project is $53,777,690. (Barrett)

Position of the Parties

FPL: The amount of total system recoverable expenses related to FPL's Woodford Project that FPL should be allowed to recover through the Fuel Clause for 2015 and 2016 are $24,611,461 and $53,777,690, respectively.

DEF: No position.

FPUC: No position.

GULF: No position.

TECO: No position.

OPC: FPL has the burden of proof to justify and support the recovery of costs and their proposal(s) seeking the Commission's adoption of policy statements (whether new or changed) or other affirmative relief sought, regardless of whether the Intervenors provide evidence to the contrary. Regardless of whether the Commission has previously approved a program or costs as meeting the Commission's requirements, the utilities must still meet their burden of demonstrating that the costs submitted for final recovery meet the statutory test(s) and are reasonable in amount and prudently incurred. The OPC takes no position on whether FPL has met its burden of proof on this issue.

FIPUG: None.

FRF: Adopts the position of OPC.

PCS Phosphate: No position.

Staff Analysis:

Argument

FPL witness Keith sponsored an exhibit reporting the company's return on capital investment and depletion for FPL's Woodford natural gas exploration and production project (the Woodford Project). (TR 31; EXH 12) As shown in the exhibit, for the period January 2015 through December 2015, the appropriate actual costs through July and estimated costs for the remaining months totaled $24,611,461, and for the period January 2016 through December 2016, the projected costs FPL should recover through the Fuel Clause for the Woodford natural gas exploration and production project is $53,777,690. (EXH 12)

FPL witness Yupp testified that the projected expenses for 2016 total about $500,000 for incremental O&M for accounting, technical services or business management functions. (TR 398) Witness Yupp stated that in 2015, the Woodford project was in the "startup phase," and that production delays and a host of other issues emerged. (TR 424-425). The witness stated, however, that the most recent production figures and expense projections show higher production volumes than prior reports, and lower expenses, resulting in a delivered price of $2.70 per mmBtu. (TR 425-426, 428) When cross examined, the witness acknowledged that low market prices contributed to overall hedging losses in 2015 for the Woodford Project. (TR 427) Witness Yupp testified that FPL earned a return on its Woodford Project investment, although he stated this project will benefit ratepayers by providing a long-term stable volume of gas at a fixed cost. (TR 425 448)

Analysis

On June 25, 2014, FPL petitioned the Commission for a determination that it was prudent for FPL to acquire an interest in a natural gas reserve project (the Woodford Project) and that the revenue requirement associated with investing in and operating the gas reserve project was eligible for recovery through the Fuel Clause. In Order No. PSC-15-0038-FOF-EI [8] (Woodford Order), the Commission found that the Woodford Project was in the public interest and its costs were recoverable through the Fuel Clause. OPC and FIPUG have filed appeals of the Woodford Order with the Florida Supreme Court, which are pending as of the date of this memorandum[9].

As summarized in the Woodford Order, the Woodford Project is a capital investment by which FPL invests directly in shale gas reserves in the Woodford Shale region of Oklahoma and ratepayers pay natural gas production costs rather than the market price on the physical gas produced.

> Historically, production costs have been less volatile than market prices. We find the Woodford Project will act as a hedge that is designed to decouple costs from market prices.[10] The Woodford Project costs are based solely on the operations and maintenance costs, and on the investment that is required, and is essentially fixed. FPL purchases more natural gas than any other electric utility in the country. The reality is that in this state, and nationally, we continue to grow the need for natural gas to provide electricity as we move away from coal. Although the Woodford Project is relatively small and will have a small effect on FPL's overall cost of natural gas and on price hedging, it will act as a long-term physical hedge (30 years or longer in duration) compared to financial hedges, which typically lock in prices for 12 – 24 months. Fuel and related costs that are subject to volatile changes are recoverable through the Fuel Clause.[11] We have allowed

[8]Order No. PSC-15-0038-FOF-EI, issued January 12, 2015, in Docket No. 150001-EI, *In re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.
[9]On March 30, 2015, the Florida Supreme Court consolidated OPC's three appeals and the FIPUG appeal into a single case (Florida Supreme Court Case No. SC15-95).
[10]Customers currently bear certain drilling, production, and shale gas risks (earthquakes, environmental issues, etc.) as these factors are embedded in the market price of gas.
[11]Order No. 14546, issued July 8, 1985, in Docket No. 850001-EI-B, *In re: Cost recovery Methods for Fuel-Related Expenses*.

> non-fuel items to be recovered through the Fuel Clause as long as they are projected to result in fuel savings.[12] FPL's natural gas price forecasts of October 2013 and July 2014 indicate that the Woodford Project will likely produce positive customer fuel savings over the life of the Project based on combinations of two factors: well productivity and natural gas market price. Under FPL's July 2014 natural gas price forecast, 6 of 9 sensitivities produce positive customer savings. ...

(Order No. PSC-15-0038-FOF-EI, pp. 4-5)

Staff acknowledges the Commission's approval of the Woodford Project is presently subject to certain appeals at the Florida Supreme Court. However, no motions to stay have been filed and the Woodford Order remains in full force and effect. Nonetheless, FPL has moved forward with its investment, and drilling and production activity began earlier this year. Therefore, staff recommends FPL is entitled to recover its Woodford Project costs through the Fuel Clause.

Conclusion

Staff recommends that for the period January 2015 through December 2015, the appropriate actual/estimated costs FPL should recover through the Fuel Clause for the Woodford natural gas exploration and production project is $24,611,461. For the period January 2016 through December 2016, the appropriate projected costs FPL should recover through the Fuel Clause for the Woodford natural gas exploration and production project is $53,777,690.

[12]Order Nos. PSC-97-0359-FOF-EI, issued March 31, 1997, in Docket 970001-EI, *In re: Fuel and purchased power cost recovery clause and generating performance incentive factor* (FPL investment in rail cars) and PSC-01-2516-FOF-EI, issued December 26, 2001, in Docket 010001-EI, *In re: Fuel and purchased power cost recovery clause and generating performance incentive factor* (Incremental Power Plant Security Costs).

Issue 4A: Should FPUC be permitted to recover the cost (depreciation expense, taxes, and return on investment) of building an interconnection between FPL's substation and FPUC's Northeast Division through the fuel recovery clause?

Recommendation: No. (Brownless)

Position of the Parties

FPL: No position.

DEF: No position.

FPUC: Yes. The project costs constitute unanticipated fuel-related costs not included in the computation of base rates for the Company. The project itself is designed to lower the delivered price of purchased power to the Company, which will produce savings for FPUC's customers.

GULF: No position.

TECO: No position.

OPC: No. Transmission costs are traditionally and historically recovered through base rates, not the fuel clause, and are not fossil fuel-related costs. Therefore, FPUC's request for fuel clause recovery violates the Company's base rate case Settlement. Further, FPUC's argument that the transmission costs should be recovered as 2016 fuel costs should be rejected since any potential "fuel savings" cannot occur in 2016 because the current PPA does not expire until 2017 and this plant will not go into service until the end of 2017. The $107,333 revenue requirement impact should be removed from the 2016 projected fuel factor calculation.

FIPUG: No. Such costs should be recovered in base rates, not through the fuel clause. Furthermore, any lobbying-type expenses should not be recovered.

FRF: Adopts the position of OPC.

PCS Phosphate: No. The Florida Public Utilities Company's proposal to recover the costs of an interconnection project through the fuel recovery clause would be an inappropriate use of the fuel recovery clause and should be denied.

Staff Analysis:

Background

FPUC has requested that it be allowed to recover $107,333 in 2016, the depreciation expense, taxes other than income taxes and a return on investment associated with the $3.5 million dollar cost of rerouting FPUC's 138 KV transmission line to parallel an existing FPL 230 KV line and upgrading FPL's substation to accommodate this interconnection. (TR 571, 594-596, 626; EXH 34) At this time, FPUC's 138 KV transmission is directly connected to the JEA 138 KV transmission network. (TR 594) If construction is started in 2016, the completion date is expected during the latter half of 2017. (TR 595) FPUC has estimated that savings will result from this interconnection for essentially two reasons: 1) improved system reliability on FPUC's transmission system; and 2) the ability to purchase power from other wholesale providers without incurring additional transmission wheeling costs which should result in lower purchased power costs. (TR 595-597) FPL will be constructing the transmission line with the costs to be reimbursed by FPUC. (TR 633)

FPUC does not generate any electricity but is solely dependent on wholesale purchase power agreements to meet its capacity and energy needs. (TR 567, 600) At this time, FPUC has wholesale power purchase agreements with JEA which service its Northeastern Division (Amelia Island) and Gulf Power Company (Gulf Power) which service its Northwestern Division (Marianna). (TR 603) Both of these wholesale purchased power contracts include payments for JEA's and Gulf Power's transmission rate base costs to provide power to FPUC. (TR 577, 615-616) However, FPUC does not currently recover any of its own transmission rate base costs through the fuel clause. (TR 616) FPUC's current contract with JEA is set to expire in December 31, 2017, the same time that FPUC's interconnection with FPL is expected to be completed. (TR 600) FPUC is required to purchase all of its wholesale purchased power from JEA during the term of the current contract. (TR 604-5) Thus, the projected $2.3 million in savings for future purchased power costs associated with the FPL interconnection can't materialize until after January 1, 2018. (TR 600, 605)

FPUC Witness Cutshaw testified that FPUC intends to issue an RFP soliciting capacity and energy for delivery at the beginning of 2018. (TR 624) Thus, while FPUC anticipates that as a result of its RFP it will be able to contract for wholesale capacity and energy at significantly lower rates once the interconnection is completed, no contracts have yet been signed and FPUC "cannot specifically define what those savings will be…" (TR 596)

When asked by several parties if FPUC would go forward with the interconnection if recovery was not allowed through the fuel clause, both Witnesses Young and Cutshaw stated that they simply didn't know. (TR 563, 572, 612-3, 633-4)

Parties' Arguments

The Commission's basic guidelines for recovery of costs through the fuel adjustment clause are found in Order No. 14546.[13] Since the issuance of Order No. 14546 in 1985, the Commission has issued 19 orders interpreting and applying these two principles to various proposed rate base capital costs for which recovery through the fuel clause was requested.[14] FPUC's brief focuses

[13]Order No. 14546, issued on July 8, 1985, in Docket No. 850001-EI,-B, *In re: Cost Recovery Methods for Fuel-Related Expenses.*

[14]Order No. PSC-11-0080-PAA-EI, issued on January 31, 2011, in Docket No. 100404-EI, *In re: Petition by Florida Power & Light Company to recover Scherer Unit 4 Turbine Upgrade costs through environmental cost recovery clause or fuel cost recovery clause* (This order includes a list of all orders between 1985 and 2005); Order No. PSC-12-0498-PAA-EI, issued on September 27, 2012, in Docket No. 120153-EI, *In re: Petition to recover capital costs of Polk Fuel Cost Reduction Project through the Fuel Cost Recovery Clause, by Tampa Electric Company*; Order No. PSC-13-0505-PAA-EI, issued on October 28, 2013, in Docket No. 130198-EI, *In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company*; Order No. PSC-14-0309-PAA-EI, issued on June 12, 2014, in Docket No. 140032-EI, *In re: Petition to recover capital costs of Big Bend fuel cost reduction project through the fuel cost recovery clause, by Tampa Electric Company*; Order No. PSC-15-0038-FOF-EI, issued on January 12, 2015, in Docket No. 150001-EI, *In re: Fuel purchased power cost recovery clause with generating performance incentive factor.*

on why its proposed transmission project qualifies for recovery through the fuel adjustment clause (FPUC BR at 5-12).

However, OPC, FRF, FIPUG, and PCS all take the position that the rate case stipulation and settlement agreement entered into between OPC and FPUC on August 29, 2014 and approved by this Commission in Order No. PSC-14-0517-S-EI, issued on September 29, 2014, (Order No. PSC-14-0517)[15] prohibits the recovery of costs associated with the FPL interconnection through the fuel clause. (OPC BR 15-18; FIPUG BR 10; PCS BR 7-9)

Section I, Term, of the settlement agreement prohibits FPUC from increasing its base rates during the minimum term of the agreement, or until after December 31, 2016. The settlement agreement also states in Section VI, Other Cost Recovery, as follows:

> Nothing in this agreement shall preclude the Company from requesting the Commission to approve the recovery of costs that are: (a) of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges or (b) incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this settlement. Except as provided in this Agreement, it is the intent of the Parties in this Paragraph VI that <u>FPUC not be allowed to recover through cost recovery clauses</u> increases in the magnitude of costs, incurred after implementation of the new base rates, of types or categories (including but not limited to, for example, <u>investment in and maintenance of transmission assets</u>) that <u>have been traditionally and historically recovered through FPUC's base rates</u>.

[Emphasis added.]

Analysis

The analysis of this issue has two parts. First, are the costs of this rate base transmission project appropriately recovered through the fuel clause? And, second, if so, is this transmission project reasonably expected to result in reductions to the purchased power costs of FPUC? Unless the first question is answered in the affirmative, the second question need not be addressed. Staff agrees with the intervenors that the rate case stipulation and settlement agreement entered into between OPC and FPUC on August 29, 2014 and approved by this Commission in Order No. PSC-14-0517-S-EI, issued on September 29, 2014, (Order No. PSC-14-0517)[16] prohibits the recovery of costs associated with the FPL interconnection through the fuel clause.

FPUC's arguments for allowing recovery for the FPL interconnection costs through the fuel adjustment clause essentially are three: 1) unlike other investor-owned utilities (IOUs), FPUC's transmission costs have traditionally and historically been recovered through the fuel clause; 2) the FPL interconnection is more than a transmission asset, it is the means by which FPUC can lower its wholesale purchased power costs; and 3) absent recovery through the fuel clause, FPUC might not be able to construct the interconnection with FPL and thereby get the benefit of

[15]Order No. PSC-14-0517-S-EI, issued on September 29, 2014, in Docket No. 140025-EI, *In re: Application for rate increase by Florida Public Utilities Company.*
[16]Order No. PSC-14-0517-S-EI, issued on September 29, 2014, in Docket No. 140025-EI, *In re: Application for rate increase by Florida Public Utilities Company.*

lower fuel costs at the expiration of its current power purchase agreement with JEA in December 2017. Staff does not find these arguments persuasive.

First, the only transmission costs that FPUC has historically recovered through the fuel clause are those of JEA and Gulf Power embedded in its current wholesale power purchase agreements with both parties. (TR 577, 615-616) None of FPUC's own transmission costs have ever been recovered through the fuel clause. (TR 616) Nor have any other IOU transmission costs been "historically" or "traditionally" recovered through the fuel clause. (TR 616) It should also be noted here that one of the benefits of the FPL interconnection testified to by witness Cutshaw is that the interconnection will significantly improve the reliability of service to Amelia Island. (TR 595-597, 600) However, capital improvements to enhance service reliability have neither "historically" nor "traditionally" been recovered through the fuel clause.

Second, FPUC failed to make the case that if recovery of the cost of the FPL interconnection through the fuel clause is disallowed, this project which FPUC believes to be valuable, would not be built or would be delayed and the benefits associated with lower costs postponed for its ratepayers. Nor did FPUC prove that completion of this transmission project is the only means by which its ratepayers could receive potential lower purchased power costs at the expiration of its contract with JEA. (TR 635) FRF, FIPUG, OPC and Commissioners all questioned FPUC's witnesses on these points. Both Witnesses Young and Cutshaw testified that FPUC would evaluate "other options" to recover the cost of the interconnection, e.g., a rate case or limited proceeding. (TR 563, 572, 613, 634, 614-616, 619-621)

Section VIII, Earnings, of the settlement agreement, states that if FPUC's earned ROE falls below 9.25 percent during the minimum term of the agreement, FPUC is permitted to file a petition for a rate increase under Sections 366.06 or 366.07, F.S., or a limited proceeding under Section 366.076, F.S. As reported in FPUC's most recent earnings surveillance report filed on September 15, 2015, FPUC's reported achieved ROE for the period ended June 30, 2015, was 4.79 percent. (EXH 124, Schedule 1) At this time FPUC is earning below 9.25 percent, the low point of the range. Thus, despite the base rate freeze currently in place as a result of the settlement, FPUC has met the settlement's conditions to release that freeze and is entitled to file for a rate base increase should recovery through the fuel clause be denied. In order to meet an in-service date for the transmission line of January 2018, a rate case filing in 2017 with rates effective the first of billing cycle of 2018 is required. (TR 614-615) Further, filing a rate case, which would involve other issues beyond the proposed FPL interconnection project, could result in a base rate increase for customers. (TR 636-637) Given these facts, staff believes that FPUC does have the option of filing for a base rate increase under the settlement agreement to recover the costs of the FPL interconnection.

Finally, FPUC has argued that the FPL interconnection is not prohibited by the settlement agreement because it will allow FPUC to reduce the price of its wholesale purchased power. For FPUC reducing the price of purchased power is the equivalent of reducing the price of fossil fuels for the other IOUs. (FPUC BR 10) FPUC argues that Order No. 14546[17] applies to purchased power as well as fossil fuels and should be used here to allow recovery of the FPL

[17]Order No. 14546, issued on July 8, 1985, in Docket No. 850001-EI-B, *In re: Cost Recovery Methods for Fuel-Related Expenses.*

interconnection costs. (FPUC BR 10-12) FPUC dismisses the plain language of Section VI of the settlement agreement which does not allow recovery of “investment in and maintenance of transmission assets that have been traditionally and historically recovered through FPUC’s base rates” on two rationales. First, Exhibit A to the settlement agreement entitled “Planned Capital Improvements” covering the period 2016-2019 does not list the FPL interconnection project. (FPUC BR 19) Second, the prohibition against recovery of transmission projects in the settlement agreement applies only to “investment in, or maintenance of, existing transmission.” (FPUC BR 19-20)

Staff agrees with FPUC that if the provisions of Order No. 14546 are not applied to purchased power, there is very little guidance as to what is recoverable in terms of purchased power through the fuel clause. (FPUC BR 10) Certainly, this is the first instance in which FPUC, the only non-generating electric utility in the state, has requested recovery of a transmission asset through the fuel clause. However, staff does not agree that the explicit terms of the settlement agreement should be dismissed summarily.

The settlement agreement does not state that the prohibition against recovery of transmission costs through the fuel clause is <u>limited</u> to the projects listed on Exhibit A. In its joint motion with OPC for approval of stipulation and settlement, FPUC stated that “FPUC will use all reasonable infrastructure projects, consistent with those outlined in demonstrative Exhibit A, attached to the Agreement, in order to maintain the reliability of its electrical system.” (Motion at 6) The joint motion also reiterates that “The Company may continue to seek recovery of costs through recovery clauses, but cannot seek recovery of costs that the Company has traditionally and historically recovered through base rates.” (Motion at 7) Given the language in its motion, the fact that the FPL interconnection was not included on Exhibit A does not support the conclusion that its costs are exempt from the settlement agreement’s specific prohibition against the recovery of transmission costs through the fuel clause. Nor does the motion’s or the settlement agreement’s prohibition against recovery through the fuel clause contain any language limiting prohibited transmission projects to existing projects. FPUC has cited no specific provision of the settlement agreement to support this contention nor is there any testimony or record evidence to support it.

Witness Cutshaw agreed that transmission rate base costs were normally recovered through base rates and that the proposed FPL interconnection was part of a transmission asset. (TR 616, 621) While there may be potential savings associated with the project, the plain language of the settlement agreement prohibiting recovery of the capital costs of transmission projects does not support recovery of these costs through the fuel adjustment clause.

Conclusion

For the reasons stated above, staff recommends that FPUC should not be allowed to recover the cost (depreciation expense, taxes, and return on investment) of building an interconnection between FPL’s substation and FPUC’s Northeast Division through the fuel recovery clause.

Issue 4B: Should FPUC's request to recover consulting and legal fees through the fuel clause be approved?

Recommendation: Yes. FPUC should continue to be allowed recovery of its consulting and legal costs associated with the review and analysis of FPUC's existing purchase power agreements and costs associated with evaluating future fuel cost saving applications through the fuel cost recovery clause. However, the true-up amount, estimated/actual costs, and projected costs should be reduced to remove consulting costs associated with the preparation of Commission filings. Within 20 days of the Commission vote, FPUC should file revised true-up and projections schedules that reflect the removal of the costs associated with the preparation of Commission filings. (Bulecza-Banks, Barrett)

Position of the Parties

FPL: No position.

DEF: No position.

FPUC: Yes. These costs are not being recovered in the Company's base rates, tend to fluctuate significantly from year to year, and are directly related to projects that will inure to the benefit of FPUC's ratepayers. Moreover, FPUC has historically recovered similar legal and consulting expenses through the fuel clause.

GULF: No position.

TECO: No position.

OPC: No. The requested consulting and legal fees are not fossil fuel-related costs recoverable through the fuel clause. FPUC's request to recover these costs in the fuel clause violates the Company's rate case Settlement pursuant to Order PSC-14- 0517-S-EI. Further, consulting and legal costs related to generation opportunities and fuel procurement administration costs, pursuant to Order No. 14546, are more appropriately recovered through base rates. Moreover, FPUC's argument that its consulting and legal fees for generation opportunities may produce fuel savings and, as such, should be recovered as 2016 fuel costs, should be rejected, as no "fuel savings" will occur in 2016.

FIPUG: No. Such costs should be recovered in base rates, not through the fuel clause. Furthermore, any lobbying-type expenses should not be recovered.

FRF: Adopts the position of OPC.

PCS Phosphate: No position.

Staff Analysis:

Background

As part of its filed petition, testimony, and supporting schedules, FPUC included actual and estimated consulting and legal fees in its fuel costs for 2014, 2015, and 2016. (TR 520, EXHs 32, 33, 34) Actual costs included in its 2014 true-up calculation are $122,933. FPUC included $111,135 in its 2015 estimated/actual costs, and $387,000 its 2016 projected costs.

The OPC, FRF, and FIPUG oppose the inclusion of legal and consulting fees in FPUC's true-up expenses for 2014, its actual/estimated fuel costs for 2015, and costs included in FPUC's calculation of its 2016 projected fuel costs. The other investor-owned utilities and PCS have taken no position on this issue.

Parties' Arguments

FPUC

FPUC believes that costs incurred and projected to be incurred for contracted consultants and legal services are directly fuel-related and will ultimately produce fuel savings that will flow to FPUC's customers through the fuel adjustment clause, and thus, are appropriate for recovery through the fuel cost recovery clause. (TR 520-523, 531-532, 589, and 591-592; BR 5) FPUC argued that the Commission has clearly stated that the purpose of the clause proceedings is to provide for recovery of volatile costs that tend to fluctuate between rate case proceedings, which if incorporated in based rates, would unduly penalize the utility or its customers.[18] (BR 6)

FPUC pointed out that no party filed testimony in the proceeding in opposition to FPUC's requested legal and consulting fees, and the only evidence in the record is that provided through the testimony of FPUC witnesses Young and Cutshaw. (BR 6)

In support of its request, FPUC witness Young argued that the consultants hired by FPUC engaged in activities related to the negotiation of a new power purchased contract with Eight Flags Energy, modification of FPUC's existing agreement with Rayonier Performance Fibers, and analysis of FPUC's current power purchase agreement to determine opportunities to produce fuel cost reductions. (TR 521; BR 13) Witness Cutshaw emphasized that the costs being requested are not associated with administrative functions associated with fuel procurement, nor associated with the Company's internal staff responsible for fuel procurement. (TR 530 and 539)

FPUC witness Young opined that that the costs FPUC is seeking to recover are similar to costs the Commission has traditionally and historically allowed recovery through the fuel clause. (TR 523; BR 14 and 20-21, EXH 89, pg. 242) In addition, witness Young pointed out that the costs requested have not been included in FPUC's base rates as these costs are volatile and fluctuate between rate case proceeding (TR 529-530, 539-540; BR 5, 6, and 21, EXH 89, pgs. 210-212)

FPUC argued that it has met its burden of proof by demonstrating that the legal and consulting fees it proposes for recovery through the fuel clause are (1) prudent expenses associated with

[18]Order No. PSC-05-0748-FOF-EI, issued July 14, 2005, in Docket No. 041272-EI, at p.37, *In Re: Petition for approval of storm cost recovery clause for recovery of extraordinary expenditures related to Hurricanes Charley, Frances, Jeanne, and Ivan, by Progress Energy Florida, Inc.*

retaining outside expertise that the Company does not otherwise have in-house (TR 538 and 540); (2) work for which these consultants were retained are associated with projects that are either currently producing fuel savings or are reasonably expected to produce savings for the Company and its customers (TR 539); and (3) expenses of a type that the Commission has traditionally allowed FPUC to recover through the fuel adjustment clause. (TR 523, BR 13 and 22)

OPC and FRF (FRF filed a Joinder in the Citizens' post-hearing statement of positions and post-hearing brief)

The OPC argues that not only does the Settlement Agreement it entered into with FPUC last year preclude FPUC from seeking recovery in the fuel clause of its legal and consulting fees, but Fuel clause Order No. 14546 also prohibits FPUC recovery of such costs.

In Order No. PSC-14-0517-S-EI, issued September 29, 2014, the Commission approved a Settlement Agreement (Settlement) between the OPC and FPUC. Paragraph VI of the Settlement, states:

> Nothing in this agreement shall preclude the Company from requesting the Commission to approve the recovery of costs that are (a) of a type which traditionally and historically would be, have been, or are presently recovered through cost recovery clauses or surcharges, or (b) incremental costs not currently recovered in base rates which the Legislature or Commission determines are clause recoverable subsequent to the approval of this settlement. Except as provided in this Agreement, it is the intent of the Parties in this Paragraph VI that FPUC not be allowed to recover through cost recovery clauses increases in the magnitude of costs, incurred after implementation of the new base rates, or types or categories (including but not limited to, for example, investment in and maintenance of transmission assets) that have been traditionally and historically recovered through FPUC’s base rates.

OPC opines that the Settlement language clearly bars FPUC from even seeking recovery in the fuel clause for cost of types or categories that have been traditionally and historically recover through FPUC’s base rates. In addition, OPC argues that the same base rate freeze anti-circumvention provision also prohibits FPUC from recovering the costs through cost recovery clauses.

OPC argues that the Commission has historically and traditionally treated allowed recovery of prudent consulting and legal generation-related costs through base rates and as FPUC does not have its own recovery history of these types of costs, they should be recovered in the same manner as have been historically and traditionally treated for other regulated electric companies. OPC accepts that FPUC was allowed recovery, on a limited basis, of its legal and consulting fees associated with purchased power agreements, but asserts that generic legal and consulting activities have not been specifically identified and allowed to be recovered through the fuel clause.

In addition, OPC argues that Fuel Clause Order No. 14546 sets forth a policy whereby costs permitted for recovery through the fuel clause must produce fuel savings. OPC asserts that the Company is simply speculating that the consulting and legal activities will result in fuel savings. While OPC acknowledges that FPUC witness Young confirmed that some of the consultant and legal activities "produced" savings, he could not identify any specific "fuel savings." (TR 576) OPC also maintains that FPUC conceded that the outside consulting and legal fees are fuel procurement and administration charges or costs that Order No. 14546 specifically precludes from recovery through the fuel clause

In conclusion, OPC argues that the FPUC's request is an attempt to circumvent the Settlement which specifically precludes FPUC from seeking recovery of costs historically and traditionally recovered through base rates. Further, OPC argues that the requested consultant and legal costs do not qualify for fuel clause recovery pursuant to Order No. 14546

FIPUG

FIPUG did not address this issue in its brief other than to provide its statement of its position: No. Such costs should be recovered in base rates, not through the fuel clause. Furthermore, any lobbying-type expenses should not be recovered.

Analysis

Commission Order No. 14546

Commission Order No. 14546, issued July 8, 1985, acknowledged the type of costs that would be permitted for recovery through the fuel cost recovery clause.[19] The order resulted from an agreement reached between staff, the Office of Public Counsel, Florida Power & Light, Florida Power Corporation (now Duke Energy Florida (DEF)), Gulf Power Company, and Tampa Electric Company. The Florida Industrial Power Users Group (FIPUG) was informed of the stipulation but it took no position.

As part of the stipulation, the two policies agreed to by the parties which they believed reflected the Commission's practical application of fuel adjustment clauses included:

1) When similar circumstances exist, the Commission should attempt to treat, for cost recovery purposes, specific types of fossil-fuel related expenses in a uniform manner among the various electric utilities. At times, however, it may be appropriate to treat similar types of expenses in dissimilar ways.
2) Prudently incurred fossil fuel-related expenses which are subject to volatile changes should be recovered through an electric utility's fuel adjustment clause…

In addition, the parties recommended to the Commission that the policy be flexible so that costs normally recovered through base rates, could be recovered through the fuel adjustment clause where the utility took advantage of a cost-effective transaction and those costs were not recognized or anticipated in the level of costs used to establish the utility's base rates. As stated

[19]Order No. 14546, issued on July 8, 1985, in Docket No. 850001-EI, *In re: Cost Recovery Methods for Fuel-Related Expenses*.

in the order, "The Commission shall rule on the appropriate method of cost recovery based upon the merits of each individual case."

Since its issuance 30 years ago, the types of costs allowed recovery through the fuel clause has evolved to include prudent, non-fossil fuel-related costs. Examples of costs that have been permitted recovery through the fuel clause that are not fossil-fuel related include nuclear fuel disposal costs,[20] incremental power plant security cost,[21] capital and operating and maintenance costs for Nuclear Regulatory Commission compliance with post Fukushima standards.[22] The recovery of such costs was not contemplated at the time the Order was issued in 1985.

With respect to fuel-savings, Order No. 14546 set forth a policy whereby recovery of fossil fuel-related costs normally recovered through base rates but which were not recognized or anticipated in the cost levels used to determine current base rates and which, if expended, will result in fuel savings to customers would be made on a case by case basis. The Order did not require that the fuel savings occur concurrently with the costs incurred.

Order No. 14546, which was the result of a Commission-approved settlement of the parties to the fuel adjustment clause proceedings, was intended to identify costs that were appropriate for cost recovery, yet recognized that the Commission had the ultimate authority to rule on the method of cost recovery.

Prior Cost Recovery of Legal and Consulting Fees

In Docket Nos. 060001-EI; 070001-EI, 080001-EI, 090001-EI, 10001-EI, 110001-EI, 120001-EI, 130001-EI, and 140001-EI, FPUC included legal and consulting fees associated with fuel-related work in its true-up filings which the Commission approved. In response to staff discovery, FPUC states that the legal and consulting fees included in its actual and projected costs are beyond the scope of normal, day-to-day fuel procurement administration functions. (EXH 89, p. 241)

The Commission has historically permitted FPUC to recover costs associated with legal and consulting fees related to purchase power agreement review and analysis. (TR 530) In Docket No. 120001-EI, FPUC was specifically granted recovery of the legal and consulting fees associated with an amendment to its Purchased Power Agreement for the Northwest Division. (EXH 89, p. 242)

As a small, non-generating investor-owned electric utility, FPUC has historically used consultants to perform a variety of activities in efforts to bring savings to its customers via lower fuel rates. (TR 520-523, 529-532, 538-539). In approving consulting costs paid by FPUC to

[20]Order No. PSC-01-2516-FOF-EI, issued December 26, 2001, in Docket No. 010001-EI, *In re: Fuel and purchased power cost recovery clause and generating performance incentive factor*.
[21]The Commission moved recovery of incremental security costs from the Fuel Clause to the capacity cost recovery clause so that the security costs were be allocated on a demand basis, in the same manner as "ordinary" security costs. See Order No. PSC-01-2516-FOF-EI, issued December 26, 2001, in Docket No. 010001-EI, *In re: Fuel and purchased power cost recovery clause and generating performance incentive factor*.
[22]Order No. PSC-13-0665-FOF-EI, issued December 18, 2013, In *re: Fuel and purchased power cost recovery clause and generating performance incentive factor*.

Christensen and Associates, the Commission distinguished FPUC from the other electric IOUs, finding that given FPUC's small size, it does not have the resources internally to prepare an RFP and evaluate responses.[23] The Commission also found that the costs associated with this type of activity are not included in base rates.[24]

Currently, the consulting and legal fees FPUC is requesting are not being recovered in base rates. In response to staff discovery, FPUC stated that the legal and consulting fees were not anticipated in the Company's last rate case, as these types of costs fluctuate significantly from year to year. (EXH 89, p. 210) Thus, FPUC did not include any costs associated with these activities in their base rate increase request. (EXH 89, p. 211)

Fuel Savings and Customer Benefit

As stated by witness Young, FPUC has been aggressively seeking opportunities to reduce fuel costs to its consumers. (TR 538) To properly and thoroughly explore fuel-saving opportunities, FPUC engages legal and consulting assistance as it lacks in-house expertise. (TR 538) Witness Young testified that the costs that FPUC is requesting to be recovered through the fuel cost recovery clause are associated with legal and consulting fees incurred in the development and enactment of projects designed to reduce fuel rates to FPUC's customers, costs associated with the development and negotiations of power supply contracts, and costs to consultants engaged in performing due diligence in review and analysis of the Renewable Energy Agreement between FPUC and Rayonier. (TR 531)

In response to staff discovery, FPUC was asked whether the costs it projects to incur in 2016 for contracted consultants and legal services will result in fuel savings to its customers. FPUC responded, "Yes, that is FPUC's goal and expectation." (EXH 89, p. 217) FPUC further states in its response that during 2016, FPUC will begin discussions with various purchased power providers in preparation for the 2017 expiration of its NE Florida wholesale power contract with JEA. Currently FPUC is reliant upon JEA for all its power needs in its NE division and is prohibited from taking power from another wholesale power provider. (EXH 90, p. 257) FPUC asserts that there will be a need for an abundance of research, analysis, and negotiation to ensure that every detail is reviewed so that FPUC obtains the best overall price for its wholesale power needs. (EXH 89, p. 217).

Conclusion

Previous Commission decisions have approved recovery of FPUC's consultant and legal fees associated with evaluating power purchase agreements, and costs that were beyond the scope of the day-to-day procurement administrative functions. In 2005, the Commission specifically recognized that due to FPUC's small size and lack of internal resources to craft a request for proposal and evaluate responses, it was appropriate to allow recovery of the consultant and legal fees associated with such activities.

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[23] Order No. PSC-05-1252-FOF-EI, issued December 23, 2005, in Docket No. 050001-EI, In *re: Fuel and purchased power cost recovery clause with generating performance incentive factor*.
[24] Ibid.

Staff believes there is no compelling reason to deviate from past Commission decisions. FPUC is still a small, non-generating electric utility that lacks the in-house expertise to find and evaluate potential opportunities for fuel savings and craft and evaluate requests for proposals for generation needs. FPUC did not include such costs in its last rate case as it believes the costs are volatile and as such, are more appropriately included for recovery in the fuel clause. At the time of its last rate case, similar costs were being recovered through the fuel clause. If recovery of these costs through the fuel clause is denied, these prudent costs would have to be absorbed by FPUC. Based on FPUC's most recently filed surveillance report, it achieved a return on equity of 4.79 percent while its approved return on equity is 10.25 percent, with a range of 9.25 to 11.25 percent.

Staff further believes that allowing recovery of FPUC's legal and consulting fees complies with Commission Order No. 14546. While the Order references fossil fuel-related expenses, the Order repeatedly provides the Commission the flexibility to determine the appropriate method of cost recovery of expenses that were not recognized or anticipated in the cost levels used to determine base rates and if expended, will result in fuel savings. The costs FPUC is requesting for recovery through the fuel clause are not related to FPUC's internal staff for fuel and purchased power procurement and administration. (TR 539) Not only has FPUC been previously allowed recovery of these types of legal and consulting fees, the types of costs that have been approved for recovery through the fuel cost recovery clause has evolved over time. Order No. 14546 was issued over 30 years ago, and while the basis for enactment of the policies reflected in the order is still valid, changes in the utility industry and the need to respond to such changes requires flexibility. Order No. 14546 repeatedly provides the Commission flexibility to address costs and transactions that were not recognized nor anticipated in the level of costs used to establish the utility's base rates. Costs that have been handled on a case-by-case basis in the fuel recovery clause include plant conversions costs, pipeline lateral costs, plant modification costs, and rail car costs. Recovery of these costs through the fuel cost recovery clause was based on estimated fuel savings. Similarly, FPUC projects that the opportunities being evaluated by its contracted consultants and legal professionals will also result in fuel savings. (EXH 89, pp. 217 and 219)

In conclusion, staff recommends that FPUC's consulting and legal fees associated with the development and enactment of projects designed to reduce fuel rates to FPUC's customers, costs associated with the development and negotiations of power supply contracts, and costs to consultants engaged in performing due diligence in review and analysis of the Renewable Energy Agreement between FPUC and Rayonier be recovered through the fuel cost recovery clause. Further, as acknowledged by Witness Young at the hearing, costs associated with a consultant who prepared Commission filings for the consolidation of FPUC's fuel divisions should be removed from its requested costs included in its true-up and projected filings. (TR 559).

Issue 5B: Should the Commission approve Gulf's 2016 Risk Management Plan?

Recommendation: Yes. Staff recommends that the Commission approve Gulf's 2016 Risk Management Plan. (Barrett, Lester)

Position of the Parties

FPL: No position.

DEF: No position.

FPUC: No position.

GULF: Yes. Gulf's 2016 Risk Management Plan for Fuel Procurement is a reasonable and prudent implementation of the Commission's hedging order and should be approved. Gulf believes that continued compliance with the "Hedging Order" provides an appropriate fuel risk management tool for utilities to utilize to limit natural gas price volatility.

TECO: No position.

OPC: No. The Risk Management Plan should not be approved as filed inasmuch as it would authorize the company to continue the financial hedging of natural gas. Incorporate by reference OPC's arguments for Issues ID & IE.

FIPUG: Hedging should be discontinued.

FRF: Adopts the position of OPC.

PCS Phosphate: No position.

Staff Analysis: Staff notes that the there is considerable overlap between the arguments Gulf presented in Issue 1D and the issue to consider the approval of Gulf's Risk Management Plan for 2016 (Issue 5B). In order to minimize duplicative arguments and for administrative efficiency, the argument for this issue will be brief and concise.

Arguments

Gulf witness Ball stated the company's Risk Management Plan has reduced fuel price volatility, which delivered fuel price stability for Gulf's rate paying customers. (TR 653, 1035) No major changes are present in Gulf's 2016 plan, according to the witness. (TR 678) In its 2016 Risk Management Plan, natural gas prices will be hedged financially using instruments that conform to the Commission's guidelines for hedging activity, and coal supply and transportation will be hedged physically using term agreements. (TR 679) Witness Ball believes Gulf's Risk Management Plan for 2016 should be approved because it presents a reasonable and appropriate strategy for protecting customers from fuel price volatility. (TR 679, 1035)

As presented in Issue 1D, OPC witness Lawton stated that prospective hedging activities should cease, and the Risk Management Plans for 2016 should not be approved. (TR 822)

Analysis

Consistent with staff's recommendation in Issue 1D that the utilities should continue natural gas financial hedging activities, staff recommends the Commission approve Gulf's 2016 Risk Management Plan. Staff believes Gulf's Risk Management Plan for 2016 provides the appropriate governance for a well-disciplined and prudently-managed utility hedging program, and is consistent with the Hedging Guidelines.

Conclusion

Staff recommends the Commission approve Gulf's 2016 Risk Management Plan.

Issue 6B: Should the Commission approve TECO's 2016 Risk Management Plan?

Recommendation: Yes. Staff recommends that the Commission approve TECO's 2016 Risk Management Plan. (Barrett, Lester)

Position of the Parties

FPL: No position.

DEF: No position.

FPUC: No position.

GULF: No position.

TECO: Yes. Tampa Electric's 2016 Risk Management Plan provides prudent nonspeculative guidelines for mitigating price volatility while ensuring supply reliability. This Plan like the ones that preceded it, has been prepared in accordance with the Commission's Hedging Order and subsequent orders refining hedging guidelines.

OPC: No. The Risk Management Plan should not be approved as filed inasmuch as it would authorize the company to continue the financial hedging of natural gas. Incorporate by reference OPC's arguments for Issues lD & IE.

FIPUG: Hedging should be discontinued.

FRF: Adopts the position of OPC.

PCS Phosphate: No position.

Staff Analysis: Staff notes that the there is considerable overlap between the arguments TECO presented in Issue 1D and the issue to consider the approval of TECO's Risk Management Plan for 2016 (Issue 6B). In order to minimize duplicative arguments and for administrative efficiency, the argument for this issue will be brief and concise.

Arguments

TECO witness Caldwell stated the company's Risk Management Plan for 2016 describes the company's strategies to mitigate fuel price volatility using a disciplined, non-speculative approach that includes financial hedges for natural gas. He stated these financial hedges are entered solely for the benefit of customers. (TR 760) Witness Caldwell asserted

> Using a disciplined, methodical, consistent natural gas financial hedging program ensures that a portion of projected natural gas needs are being hedged frequently, but never all at once. This provides known future pricing that is a blend of future prices acquired over a period of time. (TR 1058)

As presented in Issue 1D, OPC witness Lawton stated that prospective hedging activities should cease, and the Risk Management Plans for 2016 should not be approved. (TR 822)

Analysis

Consistent with staff's recommendation in Issue 1D that the utilities should continue natural gas financial hedging activities, staff recommends the Commission approve TECO's 2016 Risk Management Plan. Staff believes TECO's Risk Management Plan for 2016 provides the appropriate governance for a well-disciplined and prudently-managed utility hedging program, and is consistent with the Hedging Guidelines.

Conclusion

Staff recommends the Commission approve TECO's 2016 Risk Management Plan.

Issue 9: What are the appropriate final fuel adjustment true-up amounts for the period January 2014 through December 2014?

Recommendation: The appropriate final fuel adjustment true-up amount for the period January 2014 through December 2014 is an under-recovery of $1,474,307. (Barrett)

Position of the Parties

FPUC: $1,474,307 (Under-recovery)

OPC: The utilities have the burden of proof to justify and support the recovery of costs and their proposal(s) seeking the Commission's adoption of policy statements (whether new or changed) or other affirmative relief sought, regardless of whether the Intervenors provide evidence to the contrary. Regardless of whether the Commission has previously approved a program or costs as meeting the Commission's requirements, the utilities must still meet their burden of demonstrating that the costs submitted for final recovery meet the statutory test(s) and are reasonable in amount and prudently incurred. The OPC takes no position on whether the utilities have met their burden of proof on this issue.

FIPUG: FIPUG takes no position on this issue other than that the respective utilities must meet their burden of proof at the hearing in this matter, pursuant to applicable law, to demonstrate entitlement to the monies and other relief that the utilities request in this proceeding.

FRF: Adopts the position of OPC.

PCS Phosphate: PCS agrees with the Office of Public Counsel.

Staff Analysis: Witness Young acknowledged that FPUC has removed certain expenses[25] from its request for cost recovery of the final true-up amounts for the period January 2014 through December 2014. (TR 569; EXH 123) The expenses were for work performed to restructure FPUC's Fuel schedules (A-Schedules and E-Schedules), when the respective divisions were consolidated. (TR 558; EXH 89) The appropriate final fuel adjustment true-up amount for the period January 2014 through December 2014 is properly reflected in the brief FPUC filed on November 13, 2015. (FPUC BR 2, 22)

Staff recommends that the appropriate final fuel adjustment true-up amounts for the period January 2014 through December 2014 is an under-recovery of $1,474,307.

[25]Staff notes that the expense amount at issue is identified in Confidential Exhibit No. 123, but was subsequently disclosed in the FPUC brief on page 22 as $2,046.

Issue 10: What are the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2015 through December 2015?

Recommendation: The appropriate fuel adjustment actual/estimated true-up amounts for the period January 2015 through December 2015 is an under-recovery of $107,841. (Barrett)

Position of the Parties

FPUC: $107,841 (Under-recovery)

OPC: The utilities have the burden of proof to justify and support the recovery of costs and their proposal(s) seeking the Commission's adoption of policy statements (whether new or changed) or other affirmative relief sought, regardless of whether the Intervenors provide evidence to the contrary. Regardless of whether the Commission has previously approved a program or costs as meeting the Commission's requirements, the utilities must still meet their burden of demonstrating that the costs submitted for final recovery meet the statutory test(s) and are reasonable in amount and prudently incurred. The OPC takes no position on whether the utilities have met their burden of proof on this issue.

FIPUG: FIPUG takes no position on this issue other than that the respective utilities must meet their burden of proof at the hearing in this matter, pursuant to applicable law, to demonstrate entitlement to the monies and other relief that the utilities request in this proceeding.

FRF: Adopts the position of OPC.

PCS Phosphate: PCS agrees with the Office of Public Counsel.

Staff Analysis: Witness Young acknowledged that FPUC has removed certain expenses[26] from its request for cost recovery of the final true-up amounts for the period January 2015 through December 2015. (TR 569; EXH 89) The expenses were for work performed to restructure FPUC's Fuel schedules (A-Schedules and E-Schedules), when the respective divisions were consolidated. (TR 558; EXH 89) The appropriate fuel adjustment actual/estimated true-up amounts for the period January 2015 through December 2015 is properly reflected in the brief FPUC filed on November 13, 2015. (FPUC BR 2, 22)

Staff recommends that the appropriate fuel adjustment actual/estimated true-up amounts for the period January 2015 through December 2015 is an under-recovery of $107,841.

[26]Staff notes that the expense amount at issue is identified in Confidential Exhibit No. 89, but was subsequently disclosed in the FPUC brief on page 22 as $4,532.

Issue 11: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2016 to December 2016?

Recommendation: The appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2016 through December 2016 is an under-recovery of $1,582,148. (Barrett)

Position of the Parties

FPUC: $1,582,148 (Under-recovery)

OPC: The utilities have the burden of proof to justify and support the recovery of costs and their proposal(s) seeking the Commission's adoption of policy statements (whether new or changed) or other affirmative relief sought, regardless of whether the Intervenors provide evidence to the contrary. Regardless of whether the Commission has previously approved a program or costs as meeting the Commission's requirements, the utilities must still meet their burden of demonstrating that the costs submitted for final recovery meet the statutory test(s) and are reasonable in amount and prudently incurred. The OPC takes no position on whether the utilities have met their burden of proof on this issue.

FIPUG: FIPUG takes no position on this issue other than that the respective utilities must meet their burden of proof at the hearing in this matter, pursuant to applicable law, to demonstrate entitlement to the monies and other relief that the utilities request in this proceeding.

FRF: Adopts the position of OPC.

PCS Phosphate: PCS agrees with the Office of Public Counsel.

Staff Analysis: Witness Young acknowledged that FPUC has removed certain expenses[27] from its request for cost recovery of 2014 and 2015 true-up amounts. (TR 569; EXHs 89, 123) The sum of the expense amounts referenced in Issues 9 and 10 is properly reflected in the brief FPUC filed on November 13, 2015. (FPUC BR 2, 22)

Staff recommends that the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2016 through December 2016 are an under-recovery of $1,582,148.

[27]The expense amount for this issue is the sum of the confidential values referenced in Issues 9 and 10, which are identified in Confidential Exhibit No. 89 and 123, but was subsequently disclosed in the FPUC brief on page 22 as $6,578.

Issue 12: What are the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2016 through December 2016?

Recommendation: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2016 through December 2016 is $67,381,664. (Barrett)

Position of the Parties

FPUC: The appropriate projected total fuel and purchased power cost recovery amounts for the period January 2016 through December 2016 is $67,488,997.

OPC: The utilities have the burden of proof to justify and support the recovery of costs and their proposal(s) seeking the Commission's adoption of policy statements (whether new or changed) or other affirmative relief sought, regardless of whether the Intervenors provide evidence to the contrary. Regardless of whether the Commission has previously approved a program or costs as meeting the Commission’s requirements, the utilities must still meet their burden of demonstrating that the costs submitted for final recovery meet the statutory test(s) and are reasonable in amount and prudently incurred. The OPC takes no position on whether the utilities have met their burden of proof on this issue.

FIPUG: FIPUG takes no position on this issue other than that the respective utilities must meet their burden of proof at the hearing in this matter, pursuant to applicable law, to demonstrate entitlement to the monies and other relief that the utilities request in this proceeding.

FRF: Adopts the position of OPC.

PCS Phosphate: PCS agrees with the Office of Public Counsel.

Staff Analysis: Consistent with the recommendation for Issue 4A, the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2016 through December 2016 should not include any costs associated with FPUC’s interconnection line project with FPL.

Staff recommends that the appropriate projected total fuel and purchased power cost recovery amounts for the period January 2016 through December 2016 is $67,381,664.

Issue 19: What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2016 through December 2016?

Recommendation: The appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amount to be included in the recovery factor for the period January 2016 through December 2016 is 68,863,812. (Barrett)

Position of the Parties

FPUC: The appropriate projected amount to be included in the recovery factor for the period January 2016 through December 2016 is $68,971,145, which includes prior period true-ups.

OPC: The utilities have the burden of proof to justify and support the recovery of costs and their proposal(s) seeking the Commission's adoption of policy statements (whether new or changed) or other affirmative relief sought, regardless of whether the Intervenors provide evidence to the contrary. Regardless of whether the Commission has previously approved a program or costs as meeting the Commission's requirements, the utilities must still meet their burden of demonstrating that the costs submitted for final recovery meet the statutory test(s) and are reasonable in amount and prudently incurred. The OPC takes no position on whether the utilities have met their burden of proof on this issue.

FIPUG: FIPUG takes no position on this issue other than that the respective utilities must meet their burden of proof at the hearing in this matter, pursuant to applicable law, to demonstrate entitlement to the monies and other relief that the utilities request in this proceeding.

FRF: Adopts the position of OPC.

PCS Phosphate: PCS agrees with the Office of Public Counsel.

Staff Analysis: Consistent with the recommendation for Issue 4A, the appropriate net fuel and purchased power cost recovery and Generating Performance Incentive amount to be included in the recovery factor for the period January 2016 through December 2016 should not include any costs associated with FPUC's interconnection line project with FPL. Witness Young acknowledged that FPUC has removed certain expenses[28] from its request for cost recovery of 2014 and 2015 true-up amounts. (TR 569; EXHs, 89, 123) The sum of the expense amounts referenced in Issues 9 and 10 is also properly reflected in this issue. (FPUC BR 2)

Staff recommends that the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2016 through December 2016 is $68,863,812.

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[28] Issue 19 is a summary of the expense amounts from Issues 11 and 12. The Issue 11 expense amount is the sum of confidential amounts referenced in Issues 9 and 10, which are identified in Confidential Exhibit Nos. 89 and 123.

Issue 21: What is the appropriate levelized fuel cost recovery factor for the period January 2016 through December 2016?

Recommendation: The appropriate levelized fuel cost recovery factor for the period January 2016 through December 2016 is 6.675 cents per kilowatt hour. (Barrett)

Position of the Parties

FPUC: The appropriate factor is 6.692¢ per kWh.

OPC: The utilities have the burden of proof to justify and support the recovery of costs and their proposal(s) seeking the Commission's adoption of policy statements (whether new or changed) or other affirmative relief sought, regardless of whether the Intervenors provide evidence to the contrary. Regardless of whether the Commission has previously approved a program or costs as meeting the Commission’s requirements, the utilities must still meet their burden of demonstrating that the costs submitted for final recovery meet the statutory test(s) and are reasonable in amount and prudently incurred. The OPC takes no position on whether the utilities have met their burden of proof on this issue.

FIPUG: FIPUG takes no position on this issue other than that the respective utilities must meet their burden of proof at the hearing in this matter, pursuant to applicable law, to demonstrate entitlement to the monies and other relief that the utilities request in this proceeding.

FRF: Adopts the position of OPC.

PCS Phosphate: PCS agrees with the Office of Public Counsel.

Staff Analysis: Based on adjustments made in Issue 19, staff recommends that the appropriate levelized fuel cost recovery factor for the period January 2016 through December 2016 is 6.675 cents per kilowatt hour.

Issue 23: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

Recommendation: The appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown below in Tables 23-1 and 23-2. (Draper, Barrett, Lester)

Position of the Parties

FPUC: The appropriate levelized fuel adjustment and purchased power cost recovery factors for the period January 2016 through December 2016 are as follows:

Rate Schedule	*Adjustment*
RS	$0.10619
GS	$0.10169
GSD	$0.09709
GSLD	$0.09407
LS	$0.07211
Step rate for RS	
RS Sales	$0.10619
RS with less than 1,000 kWh/month	$0.10188
RS with more than 1,000 kWh/month	$0.11438

The appropriate adjusted Time of Use (TOU) and Interruptible rates for the Northwest Division are:

Time of Use/Interruptible

Rate Schedule	Adjustment On Peak	Adjustment Off Peak
RS	$0.18588	$0.06288
GS	$0.14169	$0.05169
GSD	$0.13709	$0.06459
GSLD	$0.15407	$0.06407
Interruptible	$0.07907	$0.09404

OPC: No position.

FIPUG: No position.

FRF: Adopts the position of OPC.

PCS Phosphate: The loss of DEF's nuclear generation and reductions it its coal-fired generation will lead to a shrinking differential between peak and off-peak fuel rates that is inconsistent with the core statutory objectives set forth in FEECA. Section 366.81, F.S. The Commission should direct DEF to address this concern in its next fuel filing.

Staff Analysis: In its brief PCS provided a position for Issue 23 with regard to DEF, not FPUC. PCS does not purchase any power from FPUC and did not take a position with regard to FPUC in its prehearing statement filed on October 9, 2015. Further, the fuel cost recovery factors for each rate class/delivery voltage level class for FPL, DEF, TECO and Gulf were part of the stipulations contained in the Notice of Stipulations filed on October 31, 2015, approved by the Commission by bench decision at the beginning of the final hearing on November 2, 2015. (Prehearing TR 11-13) PCS made no objection to the motion to approve the stipulation on Issue 23 with regard to DEF at that time. Since Issue 23 has been stipulated with regard to DEF, staff considers DEF's fuel cost recovery factors to be a moot issue.

For FPUC, staff recommends that the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses are shown in Tables 23-1 and 23-2. These factors reflect staff's recommendations for Issues 4A and 4B.

Table 23-1
2016 Fuel Cost Recovery Factors for FPUC

Rate Schedule	Levelized Adjustment
RS	$0.10602
GS	$0.10152
GSD	$0.09692
GSLD	$0.09390
LS	$0.07194
Step rate for RS	
RS Sales	$0.10602
RS with less than 1,000 kWh/month	$0.10171
RS with more than 1,000 kWh/month	$0.11421

Consistent with the fuel projections for the 2016 period, the appropriate adjusted Time of Use (TOU) and Interruptible rates for the Northwest Division for 2016 period are shown in Table 23-2 below.

Table 23-2
2016 Fuel Cost Recovery Factors for FPUC

Rate Schedule for Time of Use/Interruptible	Levelized Adjustment On Peak	Levelized Adjustment Off Peak
RS	$0.18571	$0.06271
GS	$0.14152	$0.05152
GSD	$0.13692	$0.06442
GSLD	$0.15390	$0.06390
Interruptible	$0.07890	$0.09390

Issue 37: Should this docket be closed?

Recommendation: No. The Fuel and Purchased Power Cost Recovery Clause is an on-going docket and should remain open. (Brownless)

Staff Analysis: On October 30, 2015, a Notice Of Stipulations was filed acknowledging that stipulations were entered between the parties to this docket, subject to Commission approval. This issue (Issue 37) was among several issues identified in that document. On November 2, 2015, the Commission approved the stipulations identified in the Notice of Stipulation. (TR 11-13)

The Fuel and Purchased Power Cost Recovery Clause is an on-going docket and should remain open.

Item 5

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (Mouring)
Division of Economics (Thompson)
Division of Engineering (Lee)
Office of the General Counsel (Corbari)

RE: Docket No. 140175-WU – Application for staff-assisted rate case in Pasco County by Crestridge Utilities, LLC.

AGENDA: 12/03/15 – Regular Agenda – PAA except for Issues 10 and 12

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brisé

CRITICAL DATES: 02/08/16 (15-month effective date (SARC))

SPECIAL INSTRUCTIONS: None

Table of Contents

Case Background

Crestridge Utilities, LLC. (Crestridge or utility) is a Class C water utility serving approximately 614 customers in Pasco County. Crestridge's service territory is located in the Southwest Florida Water Management District (SWFWMD) and is in a water use caution area. Crestridge's application in the instant docket shows total gross revenue of $100,193 with a net operating loss of $84,564.

Crestridge filed its application for a staff-assisted rate case (SARC) on September 10, 2014, and subsequently completed the Commission's filing requirements. November 7, 2014, was established as the official filing date in this case. Rates were last established for this utility in 1992, as a result of a staff-assisted rate case.[1] Rate base was last established for this utility when it was transferred in 2014.[2] Crestridge filed an application for transfer concurrently with this SARC. The Commission has jurisdiction in this case pursuant to Section 367.0814, Florida Statutes (F.S.).

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[1] Order No. PSC-93-0012-FOF-WU, issued January 5, 1993, in Docket No. 920417-WU, *In re: Application for staff-assisted rate case in Pasco County by Crestridge Utility Corporation.*

[2] Order No. PSC-15-0420-PAA-WU, issued October 5, 2015, in Docket No. 140174-WU, *In re: Application for approval of transfer of Certificate No. 117-W from Crestridge Utility Corporation to Crestridge Utilities, L.L.C., in Pasco County.*

Discussion of Issues

Issue 1: Is the overall quality of service provided by Crestridge satisfactory?

Recommendation: Yes, staff recommends that the quality of service provided by Crestridge be considered satisfactory. (Lee)

Staff Analysis: Pursuant to Rule 25-30.433(1), Florida Administrative Code (F.A.C.), in water and wastewater rate cases, the Commission shall determine the overall quality of service provided by a utility. This is derived from an evaluation of three separate components of the utility operations. These components are the quality of the utility's product, the operating conditions of the utility's plant and facilities, and the utility's attempt to address customer satisfaction. The rule further states that sanitary surveys, outstanding citations, violations, and consent orders on file with the Department of Environmental Protection (DEP) and the county health department over the preceding three-year period shall be considered. In addition, input from DEP and health department officials and customer comments or complaints will be considered.

Crestridge provides water service only. Crestridge's operation is subject to various environmental requirements under the jurisdiction of the DEP. In addition, the consumptive use of its water supply is under the jurisdiction of Southwest Florida Water Management District. During the utility's last SARC in 1992, the Commission found the utility's quality of service to be satisfactory based on the actions that the utility was taking in order to comply with DEP's regulations.

DEP's most recent review included an on-site inspection that was conducted on January 27, 2015. The inspection included the review of tank inspection reports, flow meter tests, and any issues observed regarding the plant operation. Based on the utility's response to DEP dated February 24, 2015, all issues observed during the inspection were addressed. The utility has indicated that it will perform any additional actions that may be required for its compliance with DEP regulations.

Section 367.0812(1)(c), F.S., requires the Commission to consider complaints filed by customers during the past five years regarding the secondary water quality standards as established by the DEP in determining whether a utility has satisfied its obligation to provide quality of water service. There has been no secondary water quality complaints based on staff's request of data from the utility and the DEP. Staff's review of customer complaints indicates the utility has resolved all of the complaints tracked by the Commission. The Commission's Consumer Activity Tracking System recorded six complaints since January 2010. Of the six complaints, four were related to billing and two were related to service quality. The last recorded complaint was closed on January 9, 2015.

A customer meeting was held on September 10, 2015, at Crestridge Gardens Community Club in Holiday, FL. Thirteen customers were present at the meeting. Two customers signed up to comment. Customers were informed about the ways to send their written comments to the Commission. Based on comments at the meeting and written comments received in this docket, the main concern appears to be the financial impact to the customers by a rate increase.

In conclusion, staff believes the utility has taken reasonable actions to comply with DEP's regulations and to address service quality concerns. Staff recommends that the quality of service provided by Crestridge be considered satisfactory.

Issue 2: What are the used and useful (U&U) percentages of Crestridge's water treatment plant (WTP) and water distribution system?

Recommendation: Staff recommends that Crestridge's water system be considered 100 percent U&U with no adjustment for Excessive Unaccounted For Water (EUW). (Lee)

Staff Analysis: The utility's water system, which includes its treatment plant and distribution system, was found to be built out and 100 percent U&U in its last SARC in Docket No. 920417-WU.[3] There has been no growth in the customer base, no change in capacity, or any plan for expansion since Crestridge's last SARC. Accordingly, staff recommends that the utility's water system be considered 100 percent U&U.

Rule 25-30.4325, F.A.C., describes Excessive Unaccounted for Water (EUW) as unaccounted for water in excess of ten percent of the amount produced or purchased. When establishing the Rule, the Commission recognized that some uses of water are readily measurable and others are not. Unaccounted for water is all water that is produced or purchased that is not sold, metered or accounted for in the records of the utility. The Rule provides that in order to determine whether adjustments to plant and operating expenses, such as purchased water, purchased electrical power and chemicals are necessary, the Commission will consider all relevant factors as to the reason for EUW, solutions implemented to correct the problem, or whether a proposed solution is economically feasible. The unaccounted for water is calculated by subtracting both the gallons used for other services, such as flushing, and the gallons sold to customers from the total gallons pumped or purchased for the test year.

During the test year, the utility produced 25.4 million gallons of water and sold 22.6 million gallons of water to customers. This results in 11 percent unaccounted for water, of which 1 percent could be considered excessive. The utility has acknowledged that many of its meters are old or not registering and in September 2014, the utility submitted a Water Loss Remedial Action Plan to the SWFWMD. In its plan, the utility has committed to, among other things, purchasing a portable hydrant meter to produce more accurate flushing records and seek the assistance of the Florida Rural Water Association in finding undetectable leaks. In addition, the utility recently replaced approximately 7 percent (42 total) of its meters and has requested an on-going aggressive meter replacement program which is discussed in Issue 3. Because the utility is implementing solutions to correct the problem, staff does not believe an adjustment for EUW should be made at this time.

In conclusion, staff recommends that the utility's water system be considered 100 percent U&U with no EUW adjustment.

[3] Order No. PSC-93-0012-FOF-WU.

Issue 3: What is the appropriate average test year water rate base for Crestridge Utilities?

Recommendation: The appropriate average test year rate base for Crestridge is $88,709 (Mouring, Lee)

Staff Analysis: The test year ended September 30, 2014, was used for the instant case. A summary of each rate base component, and recommended adjustments are discussed below.

Utility Plant in Service (UPIS)

The utility recorded UPIS of $88,524. By Order No. PSC-15-0420-PAA-WU, the Commission established a UPIS balance of $220,682 as of August 27, 2014. There were no subsequent plant additions and retirements since that point. Therefore, staff is recommending increasing UPIS by $132,157 ($220,682 - $88,524). Staff is also recommending increasing UPIS by $5,611 in consideration of pro forma plant improvements requested by the utility, and decreasing UPIS by $1,111 to include the appropriate averaging adjustment. As such, staff recommends that the appropriate UPIS balance is $225,181 ($88,525 + $132,157 + $5,611 - $1,111).

Phase I Pro Forma Additions

Staff has included the following items in its calculation of the Phase I revenue requirement because these projects have already been completed and documentation has been provided by the utility.

Table 3-1

Phase I Pro Forma Adjustments

Description	UPIS	Accum. Depr.	Depr. Exp.
New Truck	$3,818	($636)	$636
New Lawn Mower	1,076	(108)	108
Flow Meter	1,472	(98)	98
Flow Meter Retirement	(1,104)	1,104	(74)
New Meters	1,396	82	82
Retirement	(1,047)	(1,047)	(62)
Total	$5,611	$1,227	$789

In staff's first data request dated December 5, 2014, staff asked the utility to provide cost estimates and documentation of its requested pro forma plant improvements. The utility requested a portable hydrant meter and a lawn mower to be shared with Holiday Gardens Utilities, LLC and a list of equipment to be shared with other utilities under common ownership. The list of equipment includes a computer, a printer, and a truck. Subsequent to its pro forma request, the utility submitted invoices for several items including the flow meter, truck, lawn mower, and other minor repair and replacement parts needed to resolve operating issues.

As discussed in Issue 2, the utility submitted a remedial plan to the Southwest Florida Water Management District to reduce unaccounted for water. The remedial plan includes a meter replacement program to replace old and unregistering meters immediately, followed by an on-going meter replacement program. On September 29, 2015, the utility submitted invoices documenting the costs for the installation of 42 meters in accordance with the meter replacement program. Staff is recommending that the cost of these meters be capitalized. As a result, staff has increased UPIS by a net amount of $349 ($1,396 - $1,047) and decreased Accumulated Depreciation by a net amount of $965 ($1,047-82). In addition, staff has adjusted depreciation expense to reflect meter replacements and retirements, resulting in an increase of $20 ($82 - $62).

Staff's net adjustment to the Phase I UPIS balance is an increase of $5,611 and a decrease to Accumulated Depreciation of $1,227. In addition, staff has adjusted depreciation expense to reflect the pro forma additions and retirements, resulting in an increase of $789.

Further, the utility requested an on-going meter replacement program to replace the remaining meters over four years. However, staff believes a 10-year period is more appropriate and therefore staff recommends an amount of $5,981 as part of the operating expense (to be addressed in Issue 6) for the meter replacement program. Based on the unit cost of meters and parts provided by the utility, and an allowance for the number of parts needed for installation, staff estimates this amount provides replacement of 57 meters per year on average and the replacement of the remaining meters over 10 years.

For the tank replacement item, the utility provided documentation that it paid an amount of $10,000 as a down payment toward the order of the hydro-pneumatic tank priced at $22,096. Staff notes a significant decrease in the hydro-pneumatic tank cost that can be directly attributed to the utility performing a self-install of the tank. Therefore, consistent with Commission practice, staff believes items not completed should be included in a Phase II revenue requirement discussed in Issue 11.

Land & Land Rights

The utility recorded a test year land value of $6,000. Based on staff's review, no adjustments are necessary. Therefore, staff recommends that the appropriate land balance is $6,000.

Non-Used and Useful (non-U&U) Plant

As discussed in Issue 2, staff is recommending that both the water treatment plant and distribution system be considered 100 percent U&U. Therefore, no adjustment is necessary.

Contributions In Aid of Construction (CIAC)

The utility recorded a CIAC balance of $86,055. Based on staff's review, no adjustments are necessary. Therefore, staff's recommended CIAC is $86,055.

Accumulated Depreciation

Crestridge recorded a test year accumulated depreciation balance of $39,641. Staff recalculated accumulated depreciation using the prescribed rates set forth in Rule 25-30.140, F.A.C., and depreciation associated with plant additions and retirements since the utility's last rate case. Staff has increased accumulated depreciation by $124,775 to reflect the appropriate year end balance. Staff is also recommending reducing accumulated depreciation by $1,227 related to retirements associated with the pro forma items requested by the utility, and an additional $176 reduction to include the appropriate averaging adjustment. Staff's adjustment to this account results in an accumulated depreciation balance of $163,013 ($39,641 + $124,775 - $1,227 - $176).

Accumulated Amortization of CIAC

The utility did not record accumulated amortization of CIAC. Accumulated amortization of CIAC has been recalculated by staff using composite depreciation rates which resulted in an increase to accumulated amortization of CIAC $86,055. There were no additions to CIAC since the last rate case, and CIAC was fully amortized in 1999 in the amount of $86,055. Therefore, staff's recommended accumulated amortization of CIAC balance is $86,055.

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 (O&M) expense formula approach for calculating the working capital allowance. Applying this formula, staff recommends a working capital allowance of $20,541 (based on O&M expense of $164,330/8).

Rate Base Summary

Based on the foregoing, staff recommends that the appropriate average test year rate base is $88,709. Water rate base is shown on Schedule No. 1-A. The related adjustments are shown on Schedule No. 1-B.

Issue 4: What is the appropriate return on equity and overall rate of return for Crestridge Utilities?

Recommendation: The appropriate return on equity (ROE) is 11.16 percent with a range of 10.16 percent to 12.16 percent. The appropriate overall rate of return is 8.28 percent. (Mouring)

Staff Analysis: According to the staff audit, Crestridge's test year capital structure reflected common equity of $22,113, long-term debt of $211,586, short-term debt of $3,818, and customer deposits of $563. Staff has made an adjustment to the long-term debt to set it equal to the purchase price of the regulated assets of $60,694, established in the recent transfer order.[4]

The utility's capital structure has been reconciled with staff's recommended rate base. The appropriate ROE for the utility is 11.16 percent based upon the Commission-approved leverage formula currently in effect. Staff recommends an ROE of 11.16 percent, with a range of 10.16 percent to 12.16 percent, and an overall rate of return of 8.28 percent. The ROE and overall rate of return are shown on Schedule No. 2.

[4] Order No. PSC-15-0420-PAA-WU, issued October 5, 2015, in Docket No. 140174-WU, *In re: Application for approval of transfer of Certificate No. 117-W from Crestridge Utility Corporation to Crestridge Utilities, L.L.C., in Pasco County.*

Issue 5: What are the appropriate test year revenues for Crestridge?

Recommendation: The appropriate test year revenues for the Crestridge water system are $100,192. (Thompson)

Staff Analysis: Crestridge recorded total test year revenues of $98,808, which included service revenues of $90,004 and miscellaneous revenues of $8,804. Based on staff's review of the utility's billing determinants and the rates that were in effect during the test year, staff determined service revenues should be increased by $1,351 to reflect annualized test year service revenues of $91,355.[5] In addition, staff recommends increasing miscellaneous revenues by $33 to reflect the appropriate amount of miscellaneous revenues of $8,837 during the test year. Therefore, staff recommends that the appropriate test year revenues for Crestridge's water system are $100,192 ($91,355 + $8,837). Test year revenues are shown on Schedule No. 3-A.

[5] The utility filed a 2014 Index that become effective on September 2, 2014.

Issue 6: What is the appropriate amount of operating expense?

Recommendation: The appropriate amount of operating expense for the utility is $186,148. (Mouring, Lee)

Staff Analysis: Crestridge recorded operating expense of $108,096 for the test year ended September 30, 2014. The test year O&M expenses have been reviewed, including invoices, canceled checks, and other supporting documentation. Staff has made several adjustments to the utility's operating expenses as summarized below.

Operation and Maintenance Expenses

Salaries & Wages - Employees (601)

The utility recorded Salaries & Wages - Employee expense of $27,988. Staff has increased this amount by $42,533 to reflect the current allocation of employee salaries from Florida Utility Services 1, LLC. Therefore, staff recommends Salaries & Wages - Employee expense of $70,521.

Salaries & Wages - Officers (603)

The utility recorded Salaries & Wages - Officer expense of $1,965. Staff has increased this amount by $13,925 to reflect the current allocation of the utility's Officer's salary. Therefore, staff recommends Salaries & Wages - Officers expense of $15,890.

Employee Pensions and Benefits (604)

The utility recorded Pensions and Benefits expense of $4,852. Staff has increased this amount by $3,182 to reflect the current allocation of employees' medical and Workman's Compensation insurance. Therefore, staff recommends Pensions and Benefits expense of $8,034.

Chemicals (618)

The utility recorded Chemicals expense of $2,026. Staff has decreased this account by $120 to remove out-of-period expenses. Therefore, staff recommends Chemicals expense of $1,906.

Materials and Supplies (620)

Crestridge recorded Materials and Supplies expense of $1,902. This amount reflects meters and a lawnmower, which staff recommends be removed from Account 620, and capitalized to plant. The resulting amount for Materials and Supplies expense is $0.

Contractual Services - Other (636)

The utility recorded Contractual Services – Other expense of $31,951. Staff has decreased this amount by $1,493 to remove out-of-period and duplicate expenses. Staff also decreased this amount by $700 to remove lawn maintenance expense that will now be provided by the utility. The resulting amount for Contractual Services – Other expense is $29,758 ($31,951 - $1,493 - $700).

Rents (640)

Crestridge recorded Rent expense of $6,098. Staff has reduced Rent expense by $75 to reflect the appropriate allocation of the lease expense for the utility's office space. Therefore, staff recommends Rent expense of $6,023.

Insurance Expense (655)

Crestridge recorded Insurance expense of $1,210. Staff has increased Insurance expense by $2,498 ($1,203 + $2,505 - $1,210) to reflect the appropriate allocation of the auto insurance expense of $1,203, and to include the current amount of general liability insurance of $2,505. Therefore, staff recommends Insurance expense of $3,708.

Regulatory Commission Expense (665)

The utility recorded no Regulatory Commission expense for the test year. By Rule 25-30.0407, F.A.C., the utility is required to mail notices of the customer meeting and notices of final rates in this case to its customers. For these notices, staff has estimated $604 for postage expense, $432 for printing expense, and $62 for envelopes. These amounts result in $1,098 for postage, printing notices, and envelopes. The utility also requested recovery of legal fees associated with this SARC in the amount of $5,194. Staff has reviewed the support documentation and believes that $5,184 is a reasonable amount. Additionally, the utility paid a $1,000 rate case filing fee. Based on the above, staff recommends that total rate case expense is $7,292, which amortized over four years is $1,823 annually. Staff recommends Regulatory Commission expense of $1,823.

Bad Debt Expense (670)

The utility recorded no Bad Debt expense for the test year. By letter dated August 31, 2015, Crestridge requested an amount of Bad Debt expense equal to the current three-year average for bad debt expense of $300. Staff believes that a Bad Debt expense of $300 for this utility is reasonable. Staff recommends Bad Debt expense on $300.

Miscellaneous Expense (675/775)

The utility recorded Miscellaneous expense of $10,074. Staff has increased this amount by $5,981 to reflect an expedited meter replacement program. In response to a staff data request, the utility stated that it was requesting a meter change out program to be expensed, stating that it is part of its remedial action plan with the water management district. Staff also decreased this account by $2,415 to remove duplicative expenses already recorded in rent expense. Staff recommends Miscellaneous expense of $13,640 ($10,074 + $5,981 - $2,415).

Operation and Maintenance Expenses Summary

Based on the above adjustments, staff recommends that the O&M expenses are $164,330. Staff's recommended adjustments to O&M expense are shown on Schedule No. 3-A.

Depreciation Expense (Net of Amortization of CIAC)

Crestridge did not record any Depreciation expense during the test year. Staff recalculated depreciation expense using the prescribed rates set forth in Rule 25-30.140, F.A.C. As a result, staff increased depreciation expense by $4,134 to reflect the appropriate depreciation expense. Also, staff increased Depreciation expense by $789 to reflect the pro forma plant items. Therefore, staff recommends depreciation expense of $4,923 ($4,134 + $789).

Taxes Other Than Income (TOTI)

The utility recorded a TOTI balance of $7,302. Staff has increased TOTI by $29 to reflect the appropriate test year property taxes. Staff has also increased TOTI by $5,365 to reflect the appropriate allocation of payroll taxes.

In addition, as discussed in Issue 7, revenues have been increased by $93,301 to reflect the change in revenue required to cover expenses and allow the recommended return on investment. As a result, TOTI should be increased by $4,199 to reflect RAFs of 4.5 percent on the change in revenues. Therefore, staff recommends TOTI of $16,894 ($7,302 + $29 + $5,365 + $4,199).

Operating Expenses Summary

The application of staff's recommended adjustments to Crestridge's test year Operating expenses results in operating expenses of $186,148. Operating expenses are shown on Schedule No. 3-A. The related adjustments are shown on Schedule Nos. 3-B and 3-C.

Issue 7: What is the appropriate revenue requirement?

Recommendation: The appropriate revenue requirement is $193,493, resulting in an annual increase of $93,301 (93.12 percent). (Mouring)

Staff Analysis: Crestridge should be allowed an annual increase of $93,301 (93.12 percent). This will allow the utility the opportunity to recover its expenses and earn an 8.28 percent return on its water system. The calculation is shown in Table 7-1 below.

Table 7-1
Water Revenue Requirement

Adjusted Rate Base	$88,709
Rate of Return	x 8.28%
Return on Rate Base	$7,345
Adjusted O&M Expense	164,330
Depreciation Expense (Net)	4,923
Taxes Other Than Income	12,696
Incremental RAFs	4,199
Revenue Requirement	$193,493
Less Adjusted Test Year Revenues	100,192
Annual Increase	$93,301
Percent Increase	93.12%

Issue 8: What is the appropriate rate structure and rates for Crestridge?

Recommendation: The recommended rate structure and monthly water rates are shown on Schedule No. 4. 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 sheet, 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. (Thompson)

Staff Analysis: The Crestridge water system is located in Pasco County within the Southwest Florida Water Management District. The utility provides water service to approximately 613 residential customers and 1 general service customer. Approximately 24 percent of the residential customer bills during the test year had zero gallons indicating a seasonal customer base. The average residential water demand is 3,000 gallons per month. The average residential water demand excluding zero gallon bills is 3,954 gallons per month. The utility's current water system rates structure for residential and general service customers consists of a base facility charge (BFC) and a uniform gallonage charge.

Staff performed an analysis of the utility's billing data in order to evaluate the appropriate rate structure for the residential water customers. The goal of the evaluation was to select the rate design parameters that: 1) produce the recommended revenue requirement; 2) equitably distribute cost recovery among the utility's customers; 3) establish the appropriate non-discretionary usage threshold for restricting repression; and 4) implement, where appropriate, water conserving rate structures consistent with Commission practice. By letter dated October 20, 2014, the utility requested an inclining block rate structure pursuant to its existing consumptive use permit (CUP) at the time. Subsequently, the utility's CUP was renewed in October of 2015 and an inclining block rate structure was no longer a condition of the permit.

Typically, the Commission allocates no greater than 40 percent of the water revenue to the BFC. However, when the utility's customer base is seasonal, it has been the Commission's practice to allocate greater than 40 percent of the revenue requirement to the BFC to address revenue stability. Due to the customers' relatively low average monthly consumption coupled with a seasonal customer base, staff believes that it is appropriate to allocate 50 percent of the water revenue to the BFC for revenue stability purposes.

The average people per household served by the water system is two; therefore, based on the number of people per household, 50 gallons per day per person, and the number of days per month, the non-discretionary usage threshold should be 3,000 gallons per month. Approximately 63 percent of the customer bills included 3,000 gallons per month or less. Staff recommends a traditional BFC and gallonage charge rate structure with separate gallonage charges for discretionary and non-discretionary usage for residential water rates. General service customers should be billed a BFC and uniform gallonage charge. Staff's recommended rate structure and rates are shown on Schedule No. 4. Staff also presents two alternate rate structures to illustrate other BFC allocations in Table 8-1 below.

Table 8-1
Staff's Recommended and Alternative Water Rate Structures and Rates

	RATES AT TIME OF FILING	STAFF RECOMMENDED PHASE I RATES (BFC 50%)	ALTERNATIVE I (BFC 45%)	ALTERNATIVE II (BFC 55%)
Residential				
Base Facility Charge				
5/8" x 3/4"	\$7.76	\$12.43	\$11.18	\$13.68
Charge per 1,000 gallons	\$1.51	N/A	N/A	N/A
0-3,000 gallons	N/A	\$4.08	\$4.49	\$3.67
Over 3,000 gallons	N/A	\$9.22	\$11.30	\$7.54
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
3,000 Gallons	\$13.80	\$24.67	\$35.95	\$32.23
5,000 Gallons	\$15.31	\$43.11	\$47.25	\$39.77
10,000 Gallons	\$22.86	\$89.21	\$103.75	\$77.47

Based on a recommended revenue increase of approximately 102 percent, excluding miscellaneous revenues, residential consumption can be expected to decline by 5,575,000 gallons resulting in anticipated average residential demand of 2,244 gallons per month. The post-repression average residential water demand excluding zero gallon bills is anticipated to be 2,956 gallons per month. Staff recommends a 25.2 percent reduction in total residential consumption and corresponding reductions of \$970 for purchased power, \$470 for chemicals, and \$68 for RAFs to reflect the anticipated repression, which results in a post repression revenue requirement of \$183,149. Staff recommends a traditional BFC and gallonage charge rate structure with separate gallonage charges for discretionary and non-discretionary usage for residential water customers and a BFC based on 50 percent of the water revenue requirement. General service customers should be billed a BFC and uniform gallonage charge.

The recommended rate structure and monthly water rates are shown on Schedule No. 4. 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 sheet, 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 9: Should Crestridge be authorized to collect Non-Sufficient Funds (NSF) charges?

Recommendation: Yes. Crestridge should be authorized to collect NSF charges. Staff recommends that Crestridge revise its tariffs to reflect the NSF charges currently set forth in Sections 68.065 and 832.08(5), F.S. The NSF charges should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. Furthermore, the charges should not be implemented until staff has approved the proposed customer notice. The utility should provide proof of the date the notice was given within 10 days of the date of the notice. (Thompson)

Staff Analysis: Section 367.091, F.S., requires that rates, charges, and customer service policies be approved by the Commission. The Commission has authority to establish, increase, or change a rate or charge. Staff believes that Crestridge 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 Sections 832.08(5) and 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.[6] Furthermore, NSF charges place 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. Therefore, staff recommends that Crestridge revise its tariffs to reflect the NSF charges currently set forth in Sections 68.065 and 832.08(5), F.S. The NSF charges should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. In addition, the NSF charges should not be implemented until staff has approved the proposed customer notice. The utility should provide proof of the date the notice was given within 10 days of the date of the notice.

[6] Order Nos. PSC-10-0364-TRF-WS, issued June 7, 2010, in Docket No. 100170-WS, *In re: Application for authority to collect non-sufficient funds charges, pursuant to Sections 68.065 and 832.08(5), F.S., by Pluris Wedgefield Inc., and PSC-10-0168-PAA-SU,* issued March 23, 2010, in Docket No. 090182-SU, *In re: Application for increase in wastewater rates in Pasco County by Ni Florida, LLC.*

Issue 10: What are the utility's appropriate initial customer deposits for Crestridge's water service?

Recommendation: The appropriate initial customer deposit for water customers should be $49 for the residential 5/8" x 3/4" meter size. The initial customer deposits for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill for wastewater service. The approved customer deposits should be effective for 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 charges until authorized to change them by the Commission in a subsequent proceeding. (Thompson)

Staff Analysis: Rule 25-30.311, F.A.C., contains the criteria for collecting, administering, and refunding customer deposits. Customer deposits are designed to minimize the exposure of bad debt expense for the utility and, ultimately, the general body of ratepayers. Historically, the Commission has set initial customer deposits equal to two times the average estimated bill.[7] Currently, the utility's wastewater initial customer deposit is $25 for 5/8" x 3/4" meter size and two times the average estimated bill for all other meters sizes. Based on the staff recommended wastewater rates, the appropriate initial customer deposit should be $49 for water to reflect an average residential customer bill for two months.

During the course of staff's audit, it was determined that additional deposits in the amount of $15 were assessed to 88 customers, which totals $1,320. The utility required an additional deposit from those customers who had frequent shut offs due to delinquent bills. The utility confirmed that interest is paid on these accounts as required by Rule 25-30.311(4), F.A.C. Pursuant to Rule 25-30.311(7), F.A.C., a utility may require an additional deposit in order to secure payment of current bills as long as the total amount of the required deposit does not 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. Further, Rule 25-30.311(7), F.A.C. requires that request for an additional deposit be by written notice of not less than 30 days and the notice be separate and apart from any bill for service. The utility's request for the additional deposit was included on the bill for service. The utility has affirmed that in the future it will collect additional deposits in the manner required by Rule. Therefore, staff believes no enforcement action should be taken at this time.

Staff recommends the appropriate initial customer deposit should be $49 for the residential 5/8" x 3/4" meter size for wastewater. The initial customer deposits for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill for wastewater. The approved customer deposits should be effective for 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 charges until authorized to change them by the Commission in a subsequent proceeding.

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[7] Order Nos. PSC-13-0611-PAA-WS, issued November 19, 2013, in Docket No. 130010-WS, *In re: Application for increase in water rates in Lee County and wastewater rates in Pasco County by Ni Florida, LLC.* and PSC-14-0016-TRF-WU, issued January 6, 2014, in Docket No. 130251-WU, *In re: Application for approval of miscellaneous service charges in Pasco County, by Crestridge Utility Corporation.*

Issue 11: 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 367.0816, F.S.?

Recommendation: The water rates should be reduced as shown on Schedule No. 4, to remove rate case expense grossed-up for regulatory assessment fees and amortized over a four-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 367.0816, F.S. Crestridge 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. (Thompson, Mouring)

Staff Analysis: Section 367.0816, F.S., requires that the rates be reduced immediately following the expiration of the four-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. The total reduction is $1,929 for water.

Using Crestridge's current revenue, expenses, capital structure and customer base, the reduction in revenue will result in the rate decreases as shown on Schedule No. 4. The decrease in rates should become effective immediately following the expiration of the four-year rate case expense recovery period, pursuant to Section 367.0816, F.S. Crestridge 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 12: Should the Commission approve a Phase II increase for pro forma items for Crestridge?

Recommendation: Yes. The Commission should approve a Phase II revenue requirement associated with pro forma items. The utility's Phase II revenue requirement is $197,220, which equates to a 1.93 percent increase over the Phase I revenue requirement. Staff recommends that the increase be applied as an across-the-board increase to the Phase I rates.

Implementation of the Phase II rates is conditioned upon Crestridge completing the pro forma items within 12 months of the issuance of a consummating order in this docket. The utility should be required to submit a copy of the final invoices and cancelled checks or other payment confirmation documentation for all pro forma plant items. The utility should be allowed to implement the above rates once all pro forma items have been completed and documentation provided showing that the improvements have been made. Once verified, the rates should be effective for service rendered on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. The rates should not be implemented until notice has been received by the customers. Crestridge should provide proof of the date notice was given within 10 days of the date of the notice. If the utility encounters any unforeseen events that will impede the completion of the pro forma items, the utility should immediately notify the Commission in writing. (Lee, Mouring)

Staff Analysis: As discussed in Issue 3, the utility has requested recognition of several pro forma plant items in the instant case. Several of the pro forma items either have been or will be completed before implementation of the Phase I rates and, therefore, have been included in the Phase I revenue requirement as reflected in previous issues. The following table summarizes the Phase II pro forma plant items and estimated cost.

Staff is recommending a Phase II revenue requirement associated with the pro forma items for a number of reasons. First, it assures that the pro forma items are completed prior to the utility's recovery of the investment in rates. In addition, addressing the pro forma items in a single case saves additional rate case expense to the customers because the utility would not need to file another rate case or limited proceeding to seek recovery for these items. The Commission has approved a Phase-In approach in Docket Nos. 130265-WU, 110238-WU, and 110165-SU.

Staff's net adjustment to the Phase II UPIS balance is an increase of $10,370 and a decrease to Accumulated Depreciation of $27,144. In addition, staff has adjusted depreciation expense to reflect the pro forma additions and retirements resulting in an increase of $428. Also, staff has increased TOTI by $168 to reflect RAFs of 4.5 percent on the change in revenues. Staff's total adjustment to operating expenses, including additional RAFs, is $596 resulting in total operating expenses of $186,743.

Table 11-1			
Phase II Pro Forma Adjustments			
Description	UPIS	Accum. Depr.	Depr. Exp.
New Computer	$185	($31)	$31
New Printer	79	(13)	13
New Portable Meter	565	(33)	33
Check Valve at Well #2	800	(47)	47
Retirement	(600)	600	(35)
Replumb at Well #2	1,800	(67)	67
Retirement	(1,350)	1,350	(50)
Repaint at Well #2	200	(7)	7
Retirement	(150)	150	(6)
Roof at Well #2	4,000	(148)	148
Retirement	(3,000)	3,000	(111)
Air Relief Valve at Well #2	200	(12)	12
Retirement	(150)	150	(9)
Check Valve at Well #4	800	(47)	47
Retirement	(600)	600	(35)
Replumb at Well #4	1,800	(67)	67
Retirement	(1,350)	1,350	(50)
Repaint at Well #4	200	(7)	7
Retirement	(150)	150	(6)
Roof at Well #4	4,000	(148)	148
Retirement	(3,000)	3,000	(111)
Gate Valve at Well #4	1,500	(88)	88
Retirement	(1,125)	1,125	(66)
Tank Replacement	22,862	(762)	762
Retirement	(17,146)	17,146	(572)
Total	$10,370	$27,143	$428

The utility's Phase II revenue requirement should be $197,220, representing a 1.93 percent increase over the recommended Phase I revenue requirement. Phase II rate base is shown on Schedule No. 5-A. The capital structure for Phase II is shown on Schedule No. 6. The revenue requirement is shown on Schedule No. 7-A. The resulting rates are shown on Schedule No. 8.

Implementation of the Phase II rates is conditioned upon Crestridge completing the pro forma items within 12 months of the issuance of a consummating order in this docket. The utility should be required to submit a copy of the final invoices and cancelled checks for all pro forma plant items. The utility should be allowed to implement the above rates once all pro forma items have been completed and documentation provided showing that the improvements have been made. Once verified, the rates should be effective for service rendered on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. The rates should not be implemented until notice has been received by the customers. Crestridge should provide proof of the date notice was given within 10 days of the date of the notice. If the utility encounters any unforeseen events that will impede the completion of the pro forma items, the utility should immediately notify the Commission in writing.

Issue 13: Should the recommended rates be approved for the utility on a temporary basis, subject to refund with interest, in the event of a protest filed by a party other than the utility?

Recommendation: Yes. Pursuant to Section 367.0814(7), F.S., the recommended rates for Phase I should be approved for the utility on a temporary basis, subject to refund, in the event of a protest filed by a party other than the utility. Crestridge 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 sheet, pursuant to Rule 25-30.475(1), F.A.C. In addition, the temporary rates should not be implemented until staff has approved the proposed notice, and the notice has been received by the customers. Prior to implementation of any temporary rates, the utility should provide appropriate security. If the recommended rates are approved on a temporary basis, the rates collected by the utility should be subject to the refund provisions discussed below in the staff analysis. In addition, after the increased rates are in effect, pursuant to Rule 25-30.360(6), F.A.C., the utility should file reports with the Commission Clerk's office no later than the 20th of each month indicating the monthly and total amount of money subject to refund at the end of the preceding month. The report filed should also indicate the status of the security being used to guarantee repayment of any potential refund. (Mouring)

Staff Analysis: This recommendation proposes an increase in rates. A timely protest might delay what may be a justified rate increase resulting in an unrecoverable loss of revenue to the utility. Therefore, pursuant to Section 367.0814(7), F.S., in the event of a protest filed by a party other than the utility, staff recommends that the recommended rates be approved as temporary rates. Crestridge 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 sheet, pursuant to Rule 25-30.475(1), F.A.C. In addition, the temporary rates should not be implemented until staff has approved the proposed notice, and the notice has been received by the customers. The recommended rates collected by the utility should be subject to the refund provisions discussed below.

The utility should be authorized to collect the temporary rates upon staff's approval of an appropriate security for the potential refund and the proposed customer notice. Security should be in the form of a bond or letter of credit in the amount of $62,244. Alternatively, the utility could establish an escrow agreement with an independent financial institution.

If the utility chooses a bond as security, the bond should contain wording to the effect that it will be terminated only under the following conditions:

1) The Commission approves the rate increase; or
2) If the Commission denies the increase, the utility shall refund the amount collected that is attributable to the increase.

If the utility chooses a letter of credit as a security, it should contain the following conditions:

1) The letter of credit is irrevocable for the period it is in effect, and,

2) The letter of credit will be in effect until a final Commission order is rendered, either approving or denying the rate increase.

If security is provided through an escrow agreement, the following conditions should be part of the agreement:

1) The Commission Clerk, or his or her designee, must be a signatory to the escrow agreement; and,
2) No monies in the escrow account may be withdrawn by the utility without the prior written authorization of the Commission Clerk, or his or her designee;
3) The escrow account shall be an interest bearing account;
4) If a refund to the customers is required, all interest earned by the escrow account shall be distributed to the customers;
5) If a refund to the customers is not required, the interest earned by the escrow account shall revert to the utility;
6) All information on the escrow account shall be available from the holder of the escrow account to a Commission representative at all times;
7) The amount of revenue subject to refund shall be deposited in the escrow account within seven days of receipt;
8) This escrow account is established by the direction of the Florida Public Service Commission for the purpose(s) set forth in its order requiring such account. Pursuant to Cosentino v. Elson, 263 So. 2d 253 (Fla. 3d DCA 1972), escrow accounts are not subject to garnishments;
9) The account must specify by whom and on whose behalf such monies were paid.

In no instance should the maintenance and administrative costs associated with the refund be borne by the customers. These costs are the responsibility of, and should be borne by, the utility. Irrespective of the form of security chosen by the utility, an account of all monies received as a result of the rate increase should be maintained by the utility. If a refund is ultimately required, it should be paid with interest calculated pursuant to Rule 25-30.360(4), F.A.C.

The utility should maintain a record of the amount of the bond, and the amount of revenues that are subject to refund. In addition, after the increased rates are in effect, pursuant to Rule 25-30.360(6), F.A.C., the utility should file reports with the Commission Clerk's office no later than the 20th of each month indicating the monthly and total amount of money subject to refund at the end of the preceding month. The report filed should also indicate the status of the security being used to guarantee repayment of any potential refund.

Issue 14: Should the utility be required to notify the Commission within 90 days of an effective order finalizing this docket, that it has adjusted its books for all the applicable National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts (USOA) associated with the Commission approved adjustments?

Recommendation: Yes. The utility should be required to notify the Commission, in writing, that it has adjusted its books in accordance with the Commission's decision. Crestridge should submit a letter within 90 days of the final order in this docket, confirming that the adjustments to all the applicable NARUC USOA accounts have been made to the utility's books and records. In the event the utility needs additional time to complete the adjustments, notice should be provided within seven days prior to deadline. Upon providing good cause, staff should be given administrative authority to grant an extension of up to 60 days. (Mouring)

Staff Analysis: The utility should be required to notify the Commission, in writing that it has adjusted its books in accordance with the Commission's decision. Crestridge should submit a letter within 90 days of the final order in this docket, confirming that the adjustments to all the applicable NARUC USOA accounts have been made to the utility's books and records. In the event the utility needs additional time to complete the adjustments, notice should be provided within seven days prior to deadline. Upon providing good cause, staff should be given administrative authority to grant an extension of up to 60 days.

Issue 15: 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 outstanding Phase I pro forma items have been completed, the revised tariff sheets and customer notice have been filed by the utility and approved by staff, and the utility has provided staff with proof that the adjustments for all the applicable NARUC USOA primary accounts have been made. Also, the docket should remain open to allow staff to verify that the Phase II pro forma items have been completed, and the Phase II rates properly implemented. Once these actions are complete, this docket should be closed administratively. (Corbari, Mouring)

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 outstanding Phase I pro forma items have been completed, the revised tariff sheets and customer notice have been filed by the utility and approved by staff, and the utility has provided staff with proof that the adjustments for all applicable NARUC USOA primary accounts have been made. Also, the docket should remain open to allow staff to verify that the Phase II pro forma items have been completed and the Phase II rates properly implemented. Once these actions are complete, this docket should be closed administratively.

CRESTRIDGE UTILITIES, LLC | **SCHEDULE NO. 1-A**
TEST YEAR ENDED 09/30/14 | **DOCKET NO. 140175-WU**
SCHEDULE OF WATER RATE BASE (PHASE I)

DESCRIPTION	BALANCE PER UTILITY	STAFF ADJUSTMENTS TO UTIL. BAL.	BALANCE PER STAFF
UTILITY PLANT IN SERVICE	$88,524	$136,657	$225,181
LAND & LAND RIGHTS	6,000	0	6,000
NON-USED AND USEFUL COMPONENTS	0	0	0
CIAC	(86,055)	0	(86,055)
ACCUMULATED DEPRECIATION	(39,641)	(123,372)	(163,013)
AMORTIZATION OF CIAC	0	86,055	86,055
WORKING CAPITAL ALLOWANCE	0	20,541	20,541
WATER RATE BASE	($31,171)	$119,880	$88,709

CRESTRIDGE UTILITIES, LLC TEST YEAR ENDED 09/30/14 ADJUSTMENTS TO RATE BASE (PHASE I)		SCHEDULE NO. 1-B DOCKET NO. 140175-WU
		WATER
	UTILITY PLANT IN SERVICE	
1.	To reflect the appropriate UPIS.	$132,157
2.	To reflect pro forma plant additions and retirements.	5,611
3.	To reflect the appropriate averaging adjustment.	(1,111)
	Total	$136,657
	ACCUMULATED DEPRECIATION	
1.	To reflect the appropriate Accumulated Depreciation.	($124,775)
2.	To reflect pro forma plant additions and retirements.	1,227
3.	To reflect the appropriate averaging adjustment.	176
	Total	($123,372)
	AMORTIZATION OF CIAC	
	To reflect the appropriate amount of amortization.	$86,055
	WORKING CAPITAL ALLOWANCE	
	To reflect 1/8 of test year O&M expenses.	$20,541

CRESTRIDGE UTILITIES, LLC | **SCHEDULE NO. 2**
TEST YEAR ENDED 09/30/14 | **DOCKET NO. 140175-WU**
SCHEDULE OF CAPITAL STRUCTURE (PHASE I)

	CAPITAL COMPONENT	PER UTILITY	STAFF SPECIFIC ADJUST-MENTS	BALANCE BEFORE PRO RATA ADJUSTMENTS	PRO RATA ADJUST-MENTS	BALANCE PER STAFF	PERCENT OF TOTAL	COST	WEIGHTED COST
1.	COMMON EQUITY	$22,113	$0	$22,113	$388	$22,501	25.37%	11.16%	2.83%
2.	LONG-TERM DEBT	423,172	(362,478)	60,694	1,066	61,760	69.62%	7.50%	5.22%
3.	SHORT-TERM DEBT (Truck)	0	3,818	3,818	67	3,885	4.38%	5.00%	0.22%
4.	PREFERRED STOCK	0	0	0	0	0	0.00%	0.00%	0.00%
5.	CUSTOMER DEPOSITS	600	(38)	563	0	563	0.63%	2.00%	0.01%
6.	DEFERRED INCOME TAXES	0	0	0	0	0	0.00%	0.00%	0.00%
7.	TOTAL	$445,885	($358,698)	$87,188	$1,522	$88,709	100.00%		8.28%

RANGE OF REASONABLENESS	LOW	HIGH
RETURN ON EQUITY	10.16%	12.16%
OVERALL RATE OF RETURN	8.03%	8.54%

CRESTRIDGE UTILITIES, LLC | **SCHEDULE NO. 3-A**
TEST YEAR ENDED 09/30/14 | **DOCKET NO. 140175-WU**
SCHEDULE OF WATER OPERATING INCOME (PHASE I)

		TEST YEAR PER UTILITY	STAFF ADJUSTMENTS	STAFF ADJUSTED TEST YEAR	ADJUST. FOR INCREASE	REVENUE REQUIREMENT
1.	**OPERATING REVENUES**	$98,808	$1,384	$100,192	$93,301	$193,493
					93.12%	
	OPERATING EXPENSES:					
2.	OPERATION & MAINTENANCE	$100,794	$63,536	$164,330	$0	$164,330
3.	DEPRECIATION (NET)	0	4,923	4,923	0	4,923
4.	TAXES OTHER THAN INCOME	7,302	5,394	12,696	4,199	16,894
5.	INCOME TAXES	0	0	0	0	0
6.	**TOTAL OPERATING EXPENSES**	$108,096	$73,853	$181,949	$4,199	$186,148
7.	**OPERATING INCOME/(LOSS)**	($9,288)		($81,757)		$7,345
8.	**WATER RATE BASE**	($31,171)		$88,709		$88,709
9.	**RATE OF RETURN**	29.80%		(92.16%)		8.28%

CRESTRIDGE UTILITIES, LLC — **SCHEDULE NO. 3-B**
TEST YEAR ENDED 09/30/14 — **DOCKET NO. 140175-WU**
ADJUSTMENTS TO OPERATING INCOME (PHASE I) — **Page 1 of 2**

		WATER
	OPERATING REVENUES	
	a. To reflect the appropriate test year service revenues.	$1,351
	b. To reflect the test year miscellaneous service revenues.	33
	Subtotal	$1,384
	OPERATION AND MAINTENANCE EXPENSES	
1.	Salaries and Wages – Employees (601)	
	To reflect the appropriate amount of salary expense for the test year.	$42,533
2.	Salaries and Wages – Officers (603)	
	To reflect the appropriate amount of officer's salary expense for the test year.	$13,925
3.	Employee Pensions and Benefits (604)	
	To reflect the appropriate medical and workman's comp. benefits.	$3,182
4.	Chemicals (618)	
	To remove out-of-period expenses.	($120)
5.	Material and Supplies (620)	
	To reflect capitalized items.	($1,902)
6.	Contractual Services - Other (636)	
	a. To remove out-of-period expenses.	($1,493)
	b. To reflect the reduction in lawn maintenance expense.	(700)
	Subtotal	($2,193)
7.	Rents (640)	
	To reflect the appropriate rent expense.	($75)
8.	Insurance Expense (655)	
	To reflect the appropriate insurance expense.	$2,498
9.	Regulatory Commission Expense (665)	
	To reflect 4-year amortization of rate case expense.	$1,823
10.	Bad Debt Expense (670)	
	To reflect the 3-year average bad debt expense	$300
11.	Miscellaneous Expense (675)	
	a. To remove duplicate telephone and utilities expense.	($2,415)
	b. To reflect the meter replacement program expense.	5,981
	Subtotal	$3,566
	TOTAL OPERATION & MAINTENANCE ADJUSTMENTS	$63,536

(O&M EXPENSES CONTINUED ON NEXT PAGE)

CRESTRIDGE UTILITIES, LLC TEST YEAR ENDED 09/30/14 ADJUSTMENTS TO OPERATING INCOME (PHASE I)	SCHEDULE NO. 3-B DOCKET NO. 140175-WU Page 2 of 2
	WATER
DEPRECIATION EXPENSE	
To reflect appropriate depreciation expense per Rule 25-30.140 F.A.C.	$4,134
To reflect appropriate pro forma depreciation expense.	789
	$4,923
TAXES OTHER THAN INCOME	
a. To reflect the appropriate test year property taxes.	$29
b. To reflect the appropriate allocation of payroll taxes.	5,365
Total	$5,394

CRESTRIDGE UTILITIES, LLC TEST YEAR ENDED 09/30/14 ANALYSIS OF WATER OPERATION AND MAINTENANCE EXPENSE (PHASE I)			SCHEDULE NO. 3-C DOCKET NO. 140175-WU
	TOTAL PER UTILITY	STAFF ADJUST-MENTS	TOTAL PER STAFF
(601) SALARIES AND WAGES - EMPLOYEES	$27,988	$42,533	$70,521
(603) SALARIES AND WAGES - OFFICERS	1,965	13,925	15,890
(604) EMPLOYEE PENSIONS AND BENEFITS	4,852	3,182	8,034
(610) PURCHASED WATER	0	0	0
(615) PURCHASED POWER	3,938	0	3,938
(616) FUEL FOR POWER PRODUCTION	0	0	0
(618) CHEMICALS	2,026	(120)	1,906
(620) MATERIALS AND SUPPLIES	1,902	(1,902)	0
(630) CONTRACTUAL SERVICES - BILLING	4,923	0	4,923
(631) CONTRACTUAL SERVICES - PROFESSIONAL	3,035	0	3,035
(633) CONTRACTUAL SERVICES - LEGAL	0	0	0
(636) CONTRACTUAL SERVICES - OTHER	31,951	(2,193)	29,758
(640) RENTS	6,098	(75)	6,023
(650) TRANSPORTATION EXPENSE	832	0	832
(655) INSURANCE EXPENSE	1,210	2,498	3,708
(665) REGULATORY COMMISSION EXPENSE	0	1,823	1,823
(670) BAD DEBT EXPENSE	0	300	300
(675) MISCELLANEOUS EXPENSE	10,074	3,566	13,640
TOTAL WATER O&M EXPENSES	$100,794	$63,536	$164,330

CRESTRIDGE UTILITIES, LLC **SCHEDULE NO. 4**
TEST YEAR ENDED SEPTEMBER 30, 2014 **DOCKET NO. 140175-WU**
MONTHLY WATER RATES (PHASE I)

	RATES AT TIME OF FILING	STAFF RECOMMENDED RATES	4 YEAR RATE REDUCTION
Residential and General Service			
Base Facility Charge by Meter Size			
5/8" x 3/4"	$7.76	$12.43	$0.13
3/4"	$11.45	$18.65	$0.20
1"	$19.14	$31.08	$0.33
1-1/2"	$38.23	$62.15	$0.65
2"	$61.22	$99.44	$1.05
3"	$122.45	$198.88	$2.09
4"	$191.29	$310.75	$3.27
6"	$382.59	$621.50	$6.55
Charge per 1,000 gallons - Residential	$1.51	N/A	N/A
0 - 3,000 gallons	N/A	$4.08	$0.04
Over 3,000 gallons	N/A	$9.22	$0.10
Charge per 1,000 gallons - General Service	$1.51	$5.37	$0.06
Typical Residential 5/8" x 3/4" Meter Bill Comparison			
3,000 Gallons	$12.29	$24.67	
6,000 Gallons	$16.82	$52.33	
10,000 Gallons	$22.86	$89.21	

CRESTRIDGE UTILITIES, LLC **SCHEDULE NO. 5-A**
TEST YEAR ENDED 09/30/14 **DOCKET NO. 140175-WU**
SCHEDULE OF WATER RATE BASE (PHASE II)

DESCRIPTION	PHASE I BALANCE	STAFF ADJUSTMENTS TO UTIL. BAL.	BALANCE PER STAFF
UTILITY PLANT IN SERVICE	$225,181	$10,370	$235,551
LAND & LAND RIGHTS	6,000	0	6,000
NON-USED AND USEFUL COMPONENTS	0	0	0
CIAC	(86,055)	0	(86,055)
ACCUMULATED DEPRECIATION	(163,013)	27,144	(135,870)
AMORTIZATION OF CIAC	86,055	0	86,055
WORKING CAPITAL ALLOWANCE	20,541	0	20,541
WATER RATE BASE	$88,709	$37,514	$126,223

CRESTRIDGE UTILITIES, LLC TEST YEAR ENDED 09/30/14 ADJUSTMENTS TO RATE BASE (PHASE II)	SCHEDULE NO. 5-B DOCKET NO. 140175-WU
	WATER
UTILITY PLANT IN SERVICE	
To reflect pro forma plant additions and retirements.	$10,370
ACCUMULATED DEPRECIATION	
To reflect pro forma plant additions and retirements.	27,144

CRESTRIDGE UTILITIES, LLC **SCHEDULE NO. 6**
TEST YEAR ENDED 09/30/14 **DOCKET NO. 140175-WU**
SCHEDULE OF CAPITAL STRUCTURE (PHASE II)

	CAPITAL COMPONENT	PHASE I BALANCE	STAFF SPECIFIC ADJUST-MENTS	BALANCE BEFORE PRO RATA ADJUSTMENTS	PRO RATA ADJUST-MENTS	BALANCE PER STAFF	PERCENT OF TOTAL	COST	WEIGHTED COST
1.	COMMON EQUITY	$22,113	$0	$22,113	$9,965	$32,078	25.41%	11.16%	2.84%
2.	LONG-TERM DEBT	60,694	0	60,694	27,350	88,044	69.75%	7.50%	5.23%
3.	SHORT-TERM DEBT (Truck)	3,818	0	3,818	1,720	5,539	4.39%	5.00%	0.22%
4.	PREFERRED STOCK	0	0	0	0	0	0.00%	0.00%	0.00%
5.	CUSTOMER DEPOSITS	563	0	563	0	563	0.45%	2.00%	0.01%
6.	DEFERRED INCOME TAXES	0	0	0	0	0	0.00%	0.00%	0.00%
7.	TOTAL	$87,188	$0	$87,188	$39,035	$126,223	100.00%		8.30%

RANGE OF REASONABLENESS	LOW	HIGH
RETURN ON EQUITY	10.16%	12.16%
OVERALL RATE OF RETURN	8.04%	8.55%

CRESTRIDGE UTILITIES, LLC | **SCHEDULE NO. 7-A**
TEST YEAR ENDED 09/30/14 | **DOCKET NO. 140175-WU**
SCHEDULE OF WATER OPERATING INCOME (PHASE II)

		PHASE I	STAFF ADJUSTMENTS	STAFF ADJUSTED TEST YEAR	ADJUST. FOR INCREASE	REVENUE REQUIREMENT
1.	**OPERATING REVENUES**	$193,493	$0	$193,493	$3,727	$197,220
					1.93%	
	OPERATING EXPENSES:					
2.	OPERATION & MAINTENANCE	$164,330	$0	$164,330	$0	$164,330
3.	DEPRECIATION (NET)	4,923	428	5,351	0	5,351
4.	TAXES OTHER THAN INCOME	16,894	0	16,894	168	17,062
5.	INCOME TAXES	0	0	0	0	0
6.	**TOTAL OPERATING EXPENSES**	$186,148	$428	$186,575	$168	$186,743
7.	**OPERATING INCOME/(LOSS)**	$7,345		$6,918		$10,476
8.	**WATER RATE BASE**	$88,709		$126,223		$126,223
9.	**RATE OF RETURN**	8.28%		5.48%		8.30%

CRESTRIDGE UTILITIES, LLC TEST YEAR ENDED 09/30/14 ADJUSTMENTS TO OPERATING INCOME (PHASE II)	SCHEDULE NO. 7-B DOCKET NO. 140175-WU
	WATER
DEPRECIATION EXPENSE	
To reflect appropriate depreciation expense per Rule 25-30.140 F.A.C..	$428

CRESTRIDGE UTILITIES, LLC | **SCHEDULE NO. 8**
TEST YEAR ENDED SEPTEMBER 30, 2014 | **DOCKET NO. 140175-WU**
MONTHLY WATER RATES (PHASE II)

	PHASE I RATES	**STAFF RECOMMENDED RATES**
Residential and General Service		
Base Facility Charge by Meter Size		
5/8" x 3/4"	$12.43	$12.68
3/4"	$18.65	$19.02
1"	$31.08	$31.70
1-1/2"	$62.15	$63.40
2"	$99.44	$101.44
3"	$198.88	$202.88
4"	$310.75	$317.00
6"	$621.50	$634.00
Charge per 1,000 gallons - Residential	N/A	N/A
0 - 3,000 gallons	$4.08	$4.16
Over 3,000 gallons	$9.22	$9.40
Charge per 1,000 gallons - General Service	$5.37	$5.47
Typical Residential 5/8" x 3/4" Meter Bill Comparison		
3,000 Gallons	$24.67	$25.16
5,000 Gallons	$52.33	$53.36
10,000 Gallons	$89.21	$90.96

Item 6

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (Mouring)
Division of Economics (Thompson)
Division of Engineering (Lee)
Office of the General Counsel (Corbari)

RE: Docket No. 140177-WU – Application for staff-assisted rate case in Pasco County by Holiday Gardens Utilities, LLC.

AGENDA: 12/03/15 – Regular Agenda – PAA except for Issues 10 and 12

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brisé

CRITICAL DATES: 02/08/16 (15-month effective date (SARC))

SPECIAL INSTRUCTIONS: None

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Case Background

Holiday Gardens Utilities, LLC. (Holiday Gardens or utility) is a Class C water utility serving approximately 456 customers in Pasco County. Holiday Gardens' service territory is located in the Southwest Florida Water Management District (SWFWMD) and is in a water use caution area. Holiday Gardens' application in the instant docket shows total gross revenue of $77,847 with a net operating loss of $182.

Holiday Gardens filed its application for a staff-assisted rate case (SARC) on September 10, 2014, and subsequently completed the Commission's filing requirements. November 7, 2014, was established as the official filing date in this case. Rates were last established for this utility in 1992, as a result of a staff-assisted rate case.[1] Rate base was last established for this utility when it was transferred in 2014.[2] Holiday Gardens filed an application for transfer concurrently with this SARC. The Commission has jurisdiction in this case pursuant to Section 367.0814, Florida Statutes (F.S.).

[1] Order No. PSC-93-0013-FOF-WU, issued January 5, 1993, in Docket No. 920418-WU, *In re: Application for staff-assisted rate case by Holiday Gardens Utilities, Inc. in Pasco County.*
[2] Order No. PSC-15-0422-PAA-WU, issued October 6, 2015, in Docket No. 140176-WU, *In re: Application for approval of transfer of Certificate No. 116-W from Holiday Gardens Utilities, Inc. to Holiday Gardens Utilities, L.L.C., in Pasco County.*

Discussion of Issues

Issue 1: Is the overall quality of service provided by Holiday Gardens satisfactory?

Recommendation: Yes, staff recommends that the quality of service provided by the Holiday Gardens be considered satisfactory. (Lee)

Staff Analysis: Pursuant to Rule 25-30.433(1), Florida Administrative Code (F.A.C.), in water and wastewater rate cases, the Commission shall determine the overall quality of service provided by a utility. This is derived from an evaluation of three separate components of the utility operations. These components are the quality of the utility's product, the operating conditions of the utility's plant and facilities, and the utility's attempt to address customer satisfaction. The rule further states that sanitary surveys, outstanding citations, violations, and consent orders on file with the Department of Environmental Protection (DEP) and the county health department over the preceding three-year period shall be considered. In addition, input from DEP and health department officials and customer comments or complaints will be considered.

Holiday Gardens provides water service only. Holiday Gardens' operation is subject to various environmental requirements under the jurisdiction of the DEP. In addition, the consumptive use of its water supply is under the jurisdiction of Southwest Florida Water Management District. During the utility's last SARC in 1992, the Commission found the utility's quality of service to be satisfactory based on the actions that the utility was taking in order to comply with DEP's regulations.

DEP's most recent review included an on-site inspection that was conducted on January 27, 2015. The inspection included the review of tank inspection reports, flow meter tests, and any issues observed regarding the plant operation. Based on the Holiday Gardens' response to DEP dated February 24, 2015, all issues observed during the inspection were addressed. Holiday Gardens has indicated that it will perform any additional actions that may be required for its compliance with DEP regulations.

Section 367.0812(1)(c), F.S., requires the Commission to consider complaints filed by customers during the past five years regarding the secondary water quality standards as established by the DEP in determining whether a utility has satisfied its obligation to provide quality of water service. There has been no secondary water quality complaints based on staff's request of data from the utility and the DEP. Staff's review of customer complaints indicates Holiday Gardens has resolved all of the complaints tracked by the Commission. The Commission's Consumer Activity Tracking System recorded five complaints since January 2010. Of the five complaints, two were related to billing and three were related to service quality.

A customer meeting was held on September 11, 2015, at Crestridge Gardens Community Club in Holiday, Florida. Eight customers were present at the meeting. Three customers signed up to comment. Two customers voiced concern about not receiving proper boil water notices (BWN). There was also a customer who stated that the service has improved since the recent change in ownership. Staff spoke to the utility regarding provision of its BWNs and was told that it uses door hangers with standard language approved by the DEP. This method of notification is different than that provided by the prior owner, who often put notices in mailboxes. The two customers that spoke at the meeting are now aware of where to look for future notices.

Customers at the meeting were informed about the ways to send their written comments to the Commission. Based on comments received in this docket, the main concern appears to be the financial impact to the customers by a rate increase.

In conclusion, staff believes Holiday Gardens has taken reasonable actions to comply with DEP’s regulations and to address service quality concerns. Staff recommends that the quality of service provided by Holiday Gardens be considered satisfactory.

Issue 2: What are the used and useful (U&U) percentages of Holiday Gardens' water treatment plant (WTP) and water distribution system?

Recommendation: Staff recommends Holiday Gardens' water system be considered 100 percent U&U with no adjustment for Excessive Unaccounted For Water (EUW). (Lee)

Staff Analysis: The utility's water system, which includes its treatment plant and distribution system, was found to be built out and 100 percent U&U in its last SARC in Docket No. 920418-WU.[3] There has been no growth in the customer base, no change in capacity, or any plan for expansion since Holiday Gardens' last SARC. Accordingly, staff recommends that the utility's water system be considered 100 percent U&U.

Rule 25-30.4325, F.A.C., describes Excessive Unaccounted for Water (EUW) as unaccounted for water in excess of ten percent of the amount produced or purchased. When establishing the Rule, the Commission recognized that some uses of water are readily measurable and others are not. Unaccounted for water is all water that is produced or purchased that is not sold, metered or accounted for in the records of the utility. The Rule provides that in order to determine whether adjustments to plant and operating expenses, such as purchased water, purchased electrical power and chemicals are necessary, the Commission will consider all relevant factors as to the reason for EUW, solutions implemented to correct the problem, or whether a proposed solution is economically feasible. The unaccounted for water is calculated by subtracting both the gallons used for other services, such as flushing, and the gallons sold to customers from the total gallons pumped or purchased for the test year.

During the test year, the utility produced 26.9 million gallons of water and sold 21.9 million gallons of water to customers. This results in 19 percent unaccounted for water, of which 9 percent could be considered excessive. The utility has acknowledged that many of its meters are old or not registering and in September 2014, the utility submitted a Water Loss Remedial Action Plan to the SWFWMD. In its plan, the utility has committed to, among other things, purchasing a portable hydrant meter to produce more accurate flushing records and seek the assistance of the Florida Rural Water Association in finding undetectable leaks. In addition, the utility recently replaced approximately 36 percent (164 total) of its meters and has requested an aggressive on-going meter replacement program which is discussed in Issue 3. Because the utility is implementing solutions to correct the problem, staff does not believe an adjustment for EUW should be made at this time.

In conclusion, staff recommends that the utility's water system be considered 100 percent U&U with no EUW adjustment.

[3] Order No. PSC-93-0013-FOF-WU.

Issue 3: What is the appropriate average test year water rate base for Holiday Gardens?

Recommendation: The appropriate average test year rate base for Holiday Gardens is $57,727. (Mouring, Lee)

Staff Analysis: The test year ended September 30, 2014, was used for the instant case. A summary of each rate base component, and recommended adjustments are discussed below.

Utility Plant in Service (UPIS)

The utility recorded UPIS of $180,627. By Order No. PSC-15-0422-PAA-WU, the Commission established a UPIS balance of $181,038 as of August 27, 2014. There were no subsequent plant additions and retirements since that point. Therefore, staff is recommending increasing UPIS by $413 ($181,038 - $180,627). Staff increased UPIS by $250, and increased Accumulated Depreciation by $25 associated with the purchase of shop tools. Staff is also recommending increasing UPIS by $9,314 in consideration of pro forma plant improvements requested by the utility, and decreasing UPIS by $331 to include the appropriate averaging adjustment. As such, staff recommends that the appropriate UPIS balance is $190,273 ($180,627 + $413 + $250 + $9,314 - $331).

Phase I Pro Forma Additions

Staff has included the following items in its calculation of the Phase I revenue requirement because these projects have already been completed and documentation has been provided by the utility.

Table 3-1

Phase I Pro Forma Adjustments

Description	UPIS	Accum. Depr.	Depr. Exp.
New Truck	$2,827	($471)	$471
New Lawn Mower	1,250	(125)	125
Check Valve at Well #1	383	(23)	23
Retirement	(287)	287	(17)
Well Pump at Well #1	9,004	(600)	600
Retirement	(6,753)	6,753	(450)
Check Valve at Well #2	688	(40)	40
Retirement	(516)	516	(30)
New Meters	10,877	(640)	640
Retirement	(8,158)	8,158	(480)
Total	$9,314	$13,815	$922

In staff's first data request dated December 5, 2014, staff asked the utility to provide cost estimates and documentation of its requested pro forma plant improvements. The utility requested a portable hydrant meter and a lawn mower to be shared with Crestridge Utilities, LLC and a list of equipment to be shared with other utilities under common ownership. The list of equipment includes a computer, a printer, and a truck. Subsequent to its pro forma request, the utility submitted invoices for several items including the flow meter, truck, lawn mower, new well pump, valves, materials needed for repiping, and other minor repair and replacement parts needed to resolve operating issues. Consistent with Commission practice, staff believes items not completed should be included in a Phase II revenue requirement discussed in Issue 11.

As discussed in Issue 2, the utility submitted a remedial plan to the Southwest Florida Water Management District to reduce unaccounted for water. The remedial plan includes a meter replacement program to replace old and unregistering meters immediately, followed by an on-going meter replacement program. On September 29, 2015, the utility submitted invoices documenting the costs for the installation of 164 meters in accordance with the meter replacement program. Staff is recommending that the cost of these meters be capitalized. As a result, staff has increased UPIS by a net amount of $2,719 ($10,877 - $8,158) and decreased Accumulated Depreciation by a net amount of $7,518 ($8,158 – $640). In addition, staff has adjusted depreciation expense to reflect meter replacements and retirements, resulting in an increase of $160 ($640 – $480).

Staff's net adjustment to the Phase I UPIS balance is an increase of $9,314 and a decrease to Accumulated Depreciation of $13,815. In addition, staff has adjusted depreciation expense to reflect the pro forma additions and retirements, resulting in an increase of $922.

Further, the utility requested an on-going meter replacement program to replace the remaining meters over four years. However, staff believes a 10-year period is more appropriate and therefore staff recommends an amount of $3,043 as part of the operating expense (to be addressed in Issue 6) for the meter replacement program. Based on the unit cost of meters and parts provided by the utility, and an allowance for the number of parts needed for installation, staff estimates this amount provides replacement of 29 meters per year on average and the replacement of the remaining meters over 10 years.

Land & Land Rights
The utility recorded a test year land value of $3,059. In Order No. 21920, the Commission established the value of the land to be $2,414.[4] There have been no additions to purchased land since Order No. 21920 was issued. Therefore, staff recommends that the balance be reduced by $645 and that the appropriate land balance is $2,414.

Non-Used and Useful (non-U&U) Plant
As discussed in Issue 2, staff is recommending that both the water treatment plant and distribution system be considered 100 percent U&U. Therefore, no adjustment is necessary.

Contributions In Aid of Construction (CIAC)
The utility recorded a CIAC balance of $85,630. Based on staff's review, no adjustments are necessary. Therefore, staff's recommended CIAC is $85,630.

[4] Order No. 21920, issued September 19, 1989, in Docket No. 890169-WU, *In re: Application of Holiday Gardens, Inc. for staff-assisted rate case in Pasco County.*

Accumulated Depreciation

Holiday Gardens recorded a test year accumulated depreciation balance of $162,118. Staff recalculated accumulated depreciation using the prescribed rates set forth in Rule 25-30.140, F.A.C., and depreciation associated with plant additions and retirements since the utility's last rate case. Staff has increased accumulated depreciation by $1,954 to reflect the appropriate year end balance. Staff increased Accumulated Depreciation by $25 to include the purchase of shop tools. Staff is also recommending reducing accumulated depreciation by $13,815 related to retirements associated with the pro forma items requested by the utility, and an additional $978 reduction to include the appropriate averaging adjustment. Staff's adjustment to this account results in an accumulated depreciation balance of $149,305 ($162,118 + $1,954 +$25 - $13,815 - $978).

Accumulated Amortization of CIAC

The utility recorded an accumulated amortization of CIAC balance of $85,630. There were no additions to CIAC since the last rate case, and CIAC was fully amortized in 2009 in the amount of $85,630. Therefore, staff's recommended accumulated amortization of CIAC balance is $85,630.

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 (O&M) expense formula approach for calculating the working capital allowance. Applying this formula, staff recommends a working capital allowance of $14,345 (based on O&M expense of $114,763/8).

Rate Base Summary

Based on the foregoing, staff recommends that the appropriate average test year rate base is $57,727. Water rate base is shown on Schedule No. 1-A. The related adjustments are shown on Schedule No. 1-B.

Issue 4: What is the appropriate return on equity and overall rate of return for Holiday Gardens?

Recommendation: The appropriate return on equity (ROE) is 11.16 percent with a range of 10.16 percent to 12.16 percent. The appropriate overall rate of return is 8.01 percent. (Mouring)

Staff Analysis: According to the staff audit, Holiday Gardens' test year capital structure reflected common equity of $7,500, long-term debt of $211,586, short-term debt of $2,827, and customer deposits of $720. Staff has made an adjustment to the long-term debt to set it equal to the purchase price of the regulated assets of $24,544, established in the recent transfer order.[5]

The utility's capital structure has been reconciled with staff's recommended rate base. The appropriate ROE for the utility is 11.16 percent based upon the Commission-approved leverage formula currently in effect. Staff recommends an ROE of 11.16 percent, with a range of 10.16 percent to 12.16 percent, and an overall rate of return of 8.01 percent. The ROE and overall rate of return are shown on Schedule No. 2.

[5] Order No. PSC-15-0422-PAA-WU, issued October 6, 2015, in Docket No. 140176-WU, *In re: Application for approval of transfer of Certificate No. 116-W from Holiday Gardens Utilities, Inc. to Holiday Gardens Utilities, L.L.C., in Pasco County.*

Issue 5: What are the appropriate test year revenues for Holiday Gardens?

Recommendation: The appropriate test year revenues for the Holiday Gardens' water system are $79,674. (Thompson)

Staff Analysis: Holiday Gardens recorded total test year revenues of $77,847, which included service revenues of $72,113 and miscellaneous revenues of $5,734. Based on staff's review of the utility's billing determinants and the rates that were in effect during the test year, staff determined service revenues should be increased by $1,675 to reflect annualized test year service revenues of $73,788.[6] Staff also increased miscellaneous revenues by $152 to reflect the appropriate amount of $5,886 during the test year. Therefore, staff recommends that the appropriate test year revenues for Holiday Gardens' water system are $79,674 ($73,788 + $5,886). Test year revenues are shown on Schedule No. 3-A.

[6] The utility filed a 2014 Index that become effective on September 2, 2014.

Issue 6: What is the appropriate amount of operating expense?

Recommendation: The appropriate amount of operating expense for the utility is $130,686. (Mouring, Lee)

Staff Analysis: Holiday Gardens recorded operating expense of $78,029 for the test year ended September 30, 2014. The test year O&M expenses have been reviewed, including invoices, canceled checks, and other supporting documentation. Staff has made several adjustments to the utility's operating expenses as summarized below.

Operation and Maintenance Expenses

Salaries & Wages - Employees (601)

The utility recorded Salaries & Wages - Employee expense of $20,091. Staff has increased this amount by $32,113 to reflect the current allocation of employee salaries from Florida Utility Services 1, LLC. Therefore, staff recommends Salaries & Wages - Employee expense of $52,204.

Salaries & Wages - Officers (603)

The utility recorded Salaries & Wages - Officer expense of $1,455. Staff has increased this amount by $10,308 to reflect the current allocation of the utility’s Officer’s salary. Therefore, staff recommends Salaries & Wages - Officers expense of $11,763.

Employee Pensions and Benefits (604)

The utility recorded Pensions and Benefits expense of $777. Staff has increased this amount by $5,171 to reflect the current allocation of employees’ medical and Workman’s Compensation insurance. Therefore, staff recommends Pensions and Benefits expense of $5,948.

Materials and Supplies (620)

Holiday Gardens recorded Materials and Supplies expense of $1,902. This amount reflects meters and a lawnmower, which staff recommends be removed from Account 620, and capitalized to plant. The resulting amount for Materials and Supplies expense is $0.

Contractual Services - Other (636)

The utility recorded Contractual Services – Other expense of $23,445. Staff has decreased this amount by $2,015 to remove out-of-period and duplicate expenses. Staff also decreased this amount by $540 to remove lawn maintenance expense that will now be provided by the utility. The resulting amount for Contractual Services – Other expense is $20,890 ($23,445 - $2,015 - $540).

Rents (640)

Holiday Gardens recorded Rent expense of $6,398. Staff has reduced Rent expense by $1,940 to reflect the appropriate allocation of the lease expense for the utility’s office space. Therefore, staff recommends Rent expense of $4,458.

Insurance Expense (655)

Holiday Gardens recorded Insurance expense of $4,784. Staff has decreased Insurance expense by $1,716 ($890 + $2,178 - $4,784) to reflect the appropriate allocation of the auto insurance expense of $890, and to include the current amount of general liability insurance of $2,178. Therefore, staff recommends Insurance expense of $3,068.

Regulatory Commission Expense (665)

The utility recorded no Regulatory Commission expense for the test year. By Rule 25-30.0407, F.A.C., the utility is required to mail notices of the customer meeting and notices of final rates in this case to its customers. For these notices, staff has estimated $447 for postage expense, $319 for printing expense, and $46 for envelopes. These amounts result in $812 for postage, printing notices, and envelopes. The utility also requested recovery of legal fees associated with this SARC in the amount of $5,336. Staff has reviewed the support documentation and believes that $5,336 is a reasonable amount. Additionally, the utility paid a $1,000 rate case filing fee. Based on the above, staff recommends that total rate case expense is $7,148, which amortized over four years is $1,787 annually. Staff recommends a Regulatory Commission expense of $1,787.

Bad Debt Expense (670)

The utility recorded no Bad Debt expense for the test year. By letter dated August 31, 2015, Holiday Gardens requested an amount of Bad Debt expense equal to the current three-year average for bad debt expense of $300. Staff believes that a Bad Debt expense of $300 for this utility is reasonable. Staff recommends Bad Debt expense on $300

Miscellaneous Expense (675/775)

The utility recorded miscellaneous expense of $6,814. Staff has increased this amount by $3,043 to reflect an expedited meter replacement program. In response to a staff data request, the utility stated that it was requesting a meter change out program to be expensed, stating that it is part of its remedial action plan with the water management district. Staff increased this account by $1,316 to include the appropriate licensing and corporation's fees, and the normalized costs for its DEP permit renewal. Staff also decreased this account by $3,129 to remove duplicative expenses already recorded in rents expense. Staff recommends Miscellaneous expense of $8,043 ($6,814 + $3,043 + $1,316 - $3,129).

Operation and Maintenance Expenses Summary

Based on the above adjustments, staff recommends that the O&M expenses are $114,763. Staff's recommended adjustments to O&M expense are shown on Schedule No. 3-A.

Depreciation Expense (Net of Amortization of CIAC)

Holiday Gardens did not record any Depreciation expense during the test year. Staff recalculated depreciation expense using the prescribed rates set forth in Rule 25-30.140, F.A.C. As a result, staff increased depreciation expense by $1,954 to reflect the appropriate depreciation expense. Also, staff increased Depreciation expense by $922 to reflect the pro forma plant items. Therefore, staff recommends depreciation expense of $2,876 ($1,954 + $922).

Taxes Other Than Income (TOTI)

The utility recorded a TOTI balance of $6,061. Staff has increased TOTI by $37 to reflect the appropriate test year property taxes. Staff has also increased TOTI by $4,447 to reflect the appropriate allocation of payroll taxes.

In addition, as discussed in Issue 7, revenues have been increased by $55,636 to reflect the change in revenue required to cover expenses and allow the recommended return on investment. As a result, TOTI should be increased by $2,504 to reflect RAFs of 4.5 percent on the change in revenues. Therefore, staff recommends TOTI of $13,048 ($6,061 + $37 + $4,447 + $2,504).

Operating Expenses Summary

The application of staff's recommended adjustments to Holiday Gardens' test year Operating expenses results in operating expenses of $130,686. Operating expenses are shown on Schedule No. 3-A. The related adjustments are shown on Schedule Nos. 3-B and 3-C.

Issue 7: What is the appropriate revenue requirement?

Recommendation: The appropriate revenue requirement is $135,310, resulting in an annual increase of $55,636 (69.83 percent). (Mouring)

Staff Analysis: Holiday Gardens should be allowed an annual increase of $55,636 (69.83 percent). This will allow the utility the opportunity to recover its expenses and earn an 8.01 percent return on its water system. The calculation is shown in Table 7-1 below.

Table 7-1
Water Revenue Requirement

Adjusted Rate Base	$57,727
Rate of Return	x 8.01%
Return on Rate Base	$4,624
Adjusted O&M Expense	114,763
Depreciation Expense (Net)	2,876
Taxes Other Than Income	10,544
Incremental RAFs	2,504
Revenue Requirement	$135,310
Less Adjusted Test Year Revenues	79,674
Annual Increase	$55,636
Percent Increase	69.83%

Issue 8: What is the appropriate rate structure and rates for Holiday Gardens?

Recommendation: The recommended rate structure and monthly water rates are shown on Schedule No. 4. 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 sheet 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. (Thompson)

Staff Analysis: The Holiday Gardens water system is located in Pasco County within the Southwest Florida Water Management District. The utility provides water service to approximately 442 residential customers and 14 general service customers. Approximately 20 percent of the residential customer bills during the test year had zero gallons indicating a customer base that reflects some seasonality. The average residential water demand is 3,588 gallons per month. The average residential water demand excluding zero gallon bills is 4,486 gallons per month. The utility's current water system rates structure for residential and general service customers consists of a base facility charge (BFC) and a uniform gallon charge.

Staff performed an analysis of the utility's billing data in order to evaluate the appropriate rate structure for the residential water customers. The goal of the evaluation was to select the rate design parameters that: 1) produce the recommended revenue requirement; 2) equitably distribute cost recovery among the utility's customers; 3) establish the appropriate non-discretionary usage threshold for restricting repression; and 4) implement, where appropriate, water conserving rate structures consistent with Commission practice. By letter dated October 20, 2014, the utility requested an inclining block rate structure pursuant to its existing consumptive use permit (CUP) at the time. Subsequently, the utility's CUP was renewed in October of 2015 and an inclining block rate structure was no longer a condition of the permit.

Typically, the Commission allocates no greater than 40 percent of the water revenue to the BFC. However, when the utility's customer base is seasonal, it has been the Commission's practice to allocate greater than 40 percent of the revenue requirement to the BFC to address revenue stability. Due to the seasonality of the customer base and the amount of the recommended revenue increase, staff believes it is appropriate to allocate 45 percent of the water revenue to the BFC for revenue stability purposes.

The average people per household served by the water system is two; therefore, based on the number of people per household, 50 gallons per day per person, and the number of days per month, the non-discretionary usage threshold should be 3,000 gallons per month. Approximately 56 percent of the customer bills included 3,000 gallons per month or less. Staff recommends a traditional BFC and gallonage charge rate structure with separate gallonage charges for discretionary and non-discretionary usage for residential water rates. General service customers should be billed a BFC and uniform gallonage charge. Staff's recommended rate structure and rates are shown on Schedule No. 4. Staff also presents two alternate rate structures to illustrate other BFC allocations in Table 8-1 below.

Table 8-1
Staff's Recommended and Alternative Water Rate Structures and Rates

	RATES AT TIME OF FILING	STAFF RECOMMENDED PHASE I RATES (45% BFC)	ALTERNATIVE I (50% BFC)	ALTERNATIVE II (40% BFC)
Residential and General Service				
Base Facility Charge	$7.64	$9.97	$11.09	$8.86
Charge per 1,000 gallons - Residential	$1.35	N/A	N/A	N/A
0-3,000 gallons	N/A	$3.26	$2.96	$3.55
Over 3,000 gallons	N/A	$5.16	$4.50	$5.88
Charge per 1,000 gallons - General Service	$1.35	$3.91	$3.50	$4.32
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
3,000 Gallons	$11.69	$19.75	$19.97	$19.51
5,000 Gallons	$14.39	$30.07	$28.97	$31.27
10,000 Gallons	$21.14	$55.87	$51.47	$60.67

Based on a recommended revenue increase of approximately 75 percent, excluding miscellaneous revenues, residential consumption can be expected to decline by 3,774,000 gallons resulting in anticipated average residential demand of 2,876 gallons per month. The post-repression average residential water demand excluding zero gallon bills is anticipated to be 3,596 gallons per month. Staff recommends a 19.8 percent reduction in total residential consumption and corresponding reductions of $563 for purchased power, $376 for chemicals, and $44 for RAFs to reflect the anticipated repression, which results in a post repression revenue requirement of $128,441. Staff recommends a traditional BFC and gallonage charge rate structure with separate gallonage charges for discretionary and non-discretionary usage for residential water customers and a BFC based on 45 percent of the water revenue requirement. General service customers should be billed a BFC and uniform gallonage charge.

The recommended rate structure and monthly water rates are shown on Schedule No. 4. 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 sheet 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.

to

Issue 9: Should Holiday Gardens be authorized collect Non-Sufficient Funds (NSF) charges?

Recommendation: Yes. Holiday Gardens should be authorized to collect NSF charges. Staff recommends that Holiday Gardens revise its tariffs to reflect the NSF charges currently set forth in Sections 68.065 and 832.08(5), F.S. The NSF charges should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. Furthermore, the charges should not be implemented until staff has approved the proposed customer notice. The utility should provide proof of the date the notice was given within 10 days of the date of the notice. (Thompson)

Staff Analysis: Section 367.091, F.S., requires that rates, charges, and customer service policies be approved by the Commission. The Commission has authority to establish, increase, or change a rate or charge. Staff believes that Holiday Gardens 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 Sections 832.08(5) and 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.[7] Furthermore, NSF charges place 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. Therefore, staff recommends that Holiday Gardens revise its tariffs to reflect the NSF charges currently set forth in Sections 68.065 and 832.08(5), F.S. The NSF charges should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. In addition, the NSF charges should not be implemented until staff has approved the proposed customer notice. The utility should provide proof of the date the notice was given within 10 days of the date of the notice.

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[7] Order Nos. PSC-10-0364-TRF-WS, issued June 7, 2010, in Docket No. 100170-WS, *In re: Application for authority to collect non-sufficient funds charges, pursuant to Sections 68.065 and 832.08(5), F.S., by Pluris Wedgefield Inc., and PSC-10-0168-PAA-SU*, issued March 23, 2010, in Docket No. 090182-SU, *In re: Application for increase in wastewater rates in Pasco County by Ni Florida, LLC.*

Issue 10: What are the utility's appropriate initial customer deposits for Holiday Gardens' water service?

Recommendation: The appropriate initial customer deposit for water customers should be $46 for the residential 5/8" x 3/4" meter size. The initial customer deposits for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill for wastewater service. The approved customer deposits should be effective for connections made on or after the stamped approval date on the tariff sheet 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. (Thompson)

Staff Analysis: Rule 25-30.311, F.A.C., contains the criteria for collecting, administering, and refunding customer deposits. Customer deposits are designed to minimize the exposure of bad debt expense for the utility and, ultimately, the general body of ratepayers. Historically, the Commission has set initial customer deposits equal to two times the average estimated bill.[8] Currently, the utility's wastewater initial customer deposit is $24 for 5/8" x 3/4" meter size and two times the average estimated bill for all other meters sizes. Based on the staff recommended wastewater rates, the appropriate initial customer deposit should be $46 for water to reflect an average residential customer bill for two months.

During the course of staff's audit, it was determined that additional deposits in the amount of $15 were assessed to 51 customers, which totals $765. The utility required an additional deposit from those customers who had frequent shut offs due to delinquent bills. The utility confirmed that interest is paid on these accounts as required by Rule 25-30.311(4), F.A.C. Pursuant to Rule 25-30.311(7), F.A.C., a utility may require an additional deposit in order to secure payment of current bills as long as the total amount of the required deposit does not 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. Further, Rule 25-30.311(7), F.A.C. requires that request for an additional deposit be by written notice of not less than 30 days and the notice be separate and apart from any bill for service. However, the utility's request for the additional deposit was included on the bill for service. The utility has affirmed that in the future it will collect additional deposits in the manner required by Rule. Therefore, staff believes no enforcement action should be taken at this time.

Staff recommends the appropriate initial customer deposit should be $46 for the residential 5/8" x 3/4" meter size for wastewater. The initial customer deposits for all other residential meter sizes and all general service meter sizes should be two times the average estimated bill for wastewater. The approved customer deposits should be effective for connections made on or after the stamped approval date on the tariff sheet 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.

[8] Order Nos. PSC-13-0611-PAA-WS, issued November 19, 2013, in Docket No. 130010-WS, *In re: Application for increase in water rates in Lee County and wastewater rates in Pasco County by Ni Florida, LLC.* and PSC-14-0016-TRF-WU, issued January 6, 2014, in Docket No. 130251-WU, *In re: Application for approval of miscellaneous service charges in Pasco County, by Crestridge Utility Corporation.*

Issue 11: 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 367.0816, F.S.?

Recommendation: The water rates should be reduced as shown on Schedule No. 4, to remove rate case expense grossed-up for regulatory assessment fees and amortized over a four-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 367.0816, F.S. Holiday Gardens 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. (Thompson, Mouring)

Staff Analysis: Section 367.0816, F.S., requires that the rates be reduced immediately following the expiration of the four-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. The total reduction is $1,890 for water.

Using Holiday Gardens' current revenue, expenses, capital structure and customer base, the reduction in revenue will result in the rate decreases as shown on Schedule No. 4. The decrease in rates should become effective immediately following the expiration of the four-year rate case expense recovery period, pursuant to Section 367.0816, F.S. Holiday Gardens 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 12: Should the Commission approve a Phase II increase for pro forma items for Holiday Gardens?

Recommendation: Yes. The Commission should approve a Phase II revenue requirement associated with pro forma items. The utility's Phase II revenue requirement is $136,913, which equates to a 1.18 percent increase over the Phase I revenue requirement. Staff recommends that the increase be applied as an across-the-board increase to the Phase I rates.

Implementation of the Phase II rates is conditioned upon Holiday Gardens completing the pro forma items within 12 months of the issuance of a consummating order in this docket. The utility should be required to submit a copy of the final invoices and cancelled checks or other payment confirmation documentation for all pro forma plant items. The utility should be allowed to implement the above rates once all pro forma items have been completed and documentation provided showing that the improvements have been made. Once verified, the rates should be effective for service rendered on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. The rates should not be implemented until notice has been received by the customers. Holiday Gardens should provide proof of the date notice was given within 10 days of the date of the notice. If the utility encounters any unforeseen events that will impede the completion of the pro forma items, the utility should immediately notify the Commission in writing. (Lee, Mouring)

Staff Analysis: As discussed in Issue 3, the utility has requested recognition of several pro forma plant items in the instant case. Several of the pro forma items either have been or will be completed before implementation of the Phase I rates and, therefore, have been included in the Phase I revenue requirement as reflected in previous issues. The following table summarizes the Phase II pro forma plant items and estimated cost.

Staff is recommending a Phase II revenue requirement associated with the pro forma items for a number of reasons. First, it assures that the pro forma items are completed prior to the utility's recovery of the investment in rates. In addition, addressing the pro forma items in a single case saves additional rate case expense to the customers because the utility would not need to file another rate case or limited proceeding to seek recovery for these items. The Commission has approved a Phase-In approach in Docket Nos. 130265-WU, 110238-WU, and 110165-SU.

Staff's net adjustment to the Phase II UPIS balance is an increase of $4,749 and a decrease to Accumulated Depreciation of $11,208. In addition, staff has adjusted depreciation expense to reflect the pro forma additions and retirements resulting in an increase of $238. Also, staff has increased TOTI by $72 to reflect RAFs of 4.5 percent on the change in revenues. Staff's total adjustment to operating expenses, including additional RAFs, is $310 resulting in total operating expenses of $130,997.

Table 11-1			
Phase II Pro Forma Adjustments			
Description	UPIS	Accum. Depr.	Depr. Exp.
New Computer	$137	($23)	$23
New Printer	59	(10)	10
New Portable Meter	565	(33)	33
Replumb at Well #1	1,800	(67)	67
Retirement	(1,350)	1,350	(50)
Air Relief Valve at Well #1	200	(12)	12
Retirement	(150)	150	(9)
Repaint at Well #1	200	(7)	7
Retirement	(150)	150	(6)
Roof at Well #1	4,000	(148)	148
Retirement	(3,000)	3,000	(111)
Flow Meter at Well #1	1,500	(100)	100
Retirement	(1,125)	1,125	(75)
Replumb at Well #2	1,800	(67)	67
Retirement	(1,350)	1,350	(50)
Repaint at Well #2	200	(7)	7
Retirement	(150)	150	(6)
Roof at Well #2	4,000	(148)	148
Retirement	(3,000)	3,000	(111)
Gate Valve at Well #2	750	(44)	44
Retirement	(563)	563	(33)
Air Compressor at Well #2	1,500	(88)	88
Retirement	(1,125)	1,125	(66)
Total	$4,749	$11,208	$238

The utility's Phase II revenue requirement should be $136,913, representing a 1.18 percent increase over the recommended Phase I revenue requirement. Phase II rate base is shown on Schedule No. 5-A. The capital structure for Phase II is shown on Schedule No. 6. The revenue requirement is shown on Schedule No. 7-A. The resulting rates are shown on Schedule No. 8.

Implementation of the Phase II rates is conditioned upon Holiday Gardens completing the pro forma items within 12 months of the issuance of a consummating order in this docket. The utility should be required to submit a copy of the final invoices and cancelled checks for all pro forma plant items. The utility should be allowed to implement the above rates once all pro forma items have been completed and documentation provided showing that the improvements have been made. Once verified, the rates should be effective for service rendered on or after the stamped approval date on the tariff sheet, pursuant to Rule 25-30.475(1), F.A.C. The rates should not be implemented until notice has been received by the customers. Holiday Gardens should provide proof of the date notice was given within 10 days of the date of the notice. If the utility encounters any unforeseen events that will impede the completion of the pro forma items, the utility should immediately notify the Commission in writing.

Issue 13: Should the recommended rates be approved for the utility on a temporary basis, subject to refund with interest, in the event of a protest filed by a party other than the utility?

Recommendation: Yes. Pursuant to Section 367.0814(7), F.S., the recommended rates for Phase I should be approved for the utility on a temporary basis, subject to refund, in the event of a protest filed by a party other than the utility. Holiday Gardens 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 sheet, pursuant to Rule 25-30.475(1), F.A.C. In addition, the temporary rates should not be implemented until staff has approved the proposed notice, and the notice has been received by the customers. Prior to implementation of any temporary rates, the utility should provide appropriate security. If the recommended rates are approved on a temporary basis, the rates collected by the utility should be subject to the refund provisions discussed below in the staff analysis. In addition, after the increased rates are in effect, pursuant to Rule 25-30.360(6), F.A.C., the utility should file reports with the Commission Clerk's office no later than the 20th of each month indicating the monthly and total amount of money subject to refund at the end of the preceding month. The report filed should also indicate the status of the security being used to guarantee repayment of any potential refund. (Mouring)

Staff Analysis: This recommendation proposes an increase in rates. A timely protest might delay what may be a justified rate increase resulting in an unrecoverable loss of revenue to the utility. Therefore, pursuant to Section 367.0814(7), F.S., in the event of a protest filed by a party other than the utility, staff recommends that the recommended rates be approved as temporary rates. Holiday Gardens 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 sheet, pursuant to Rule 25-30.475(1), F.A.C. In addition, the temporary rates should not be implemented until staff has approved the proposed notice, and the notice has been received by the customers. The recommended rates collected by the utility should be subject to the refund provisions discussed below.

The utility should be authorized to collect the temporary rates upon staff's approval of an appropriate security for the potential refund and the proposed customer notice. Security should be in the form of a bond or letter of credit in the amount of $37,117. Alternatively, the utility could establish an escrow agreement with an independent financial institution.

If the utility chooses a bond as security, the bond should contain wording to the effect that it will be terminated only under the following conditions:

1) The Commission approves the rate increase; or
2) If the Commission denies the increase, the utility shall refund the amount collected that is attributable to the increase.

If the utility chooses a letter of credit as a security, it should contain the following conditions:

1) The letter of credit is irrevocable for the period it is in effect, and,

2) The letter of credit will be in effect until a final Commission order is rendered, either approving or denying the rate increase.

If security is provided through an escrow agreement, the following conditions should be part of the agreement:

1) The Commission Clerk, or his or her designee, must be a signatory to the escrow agreement; and,
2) No monies in the escrow account may be withdrawn by the utility without the prior written authorization of the Commission Clerk, or his or her designee;
3) The escrow account shall be an interest bearing account;
4) If a refund to the customers is required, all interest earned by the escrow account shall be distributed to the customers;
5) If a refund to the customers is not required, the interest earned by the escrow account shall revert to the utility;
6) All information on the escrow account shall be available from the holder of the escrow account to a Commission representative at all times;
7) The amount of revenue subject to refund shall be deposited in the escrow account within seven days of receipt;
8) This escrow account is established by the direction of the Florida Public Service Commission for the purpose(s) set forth in its order requiring such account. Pursuant to Cosentino v. Elson, 263 So. 2d 253 (Fla. 3d DCA 1972), escrow accounts are not subject to garnishments;
9) The account must specify by whom and on whose behalf such monies were paid.

In no instance should the maintenance and administrative costs associated with the refund be borne by the customers. These costs are the responsibility of, and should be borne by, the utility. Irrespective of the form of security chosen by the utility, an account of all monies received as a result of the rate increase should be maintained by the utility. If a refund is ultimately required, it should be paid with interest calculated pursuant to Rule 25-30.360(4), F.A.C.

The utility should maintain a record of the amount of the bond, and the amount of revenues that are subject to refund. In addition, after the increased rates are in effect, pursuant to Rule 25-30.360(6), F.A.C., the utility should file reports with the Commission Clerk’s office no later than the 20th of each month indicating the monthly and total amount of money subject to refund at the end of the preceding month. The report filed should also indicate the status of the security being used to guarantee repayment of any potential refund.

Issue 14: Should the utility be required to notify the Commission within 90 days of an effective order finalizing this docket, that it has adjusted its books for all the applicable National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts (USOA) associated with the Commission approved adjustments?

Recommendation: Yes. The utility should be required to notify the Commission, in writing, that it has adjusted its books in accordance with the Commission's decision. Holiday Gardens should submit a letter within 90 days of the final order in this docket, confirming that the adjustments to all the applicable NARUC USOA accounts have been made to the utility's books and records. In the event the utility needs additional time to complete the adjustments, notice should be provided within seven days prior to deadline. Upon providing good cause, staff should be given administrative authority to grant an extension of up to 60 days. (Mouring)

Staff Analysis: The utility should be required to notify the Commission, in writing that it has adjusted its books in accordance with the Commission's decision. Holiday Gardens should submit a letter within 90 days of the final order in this docket, confirming that the adjustments to all the applicable NARUC USOA accounts have been made to the utility's books and records. In the event the utility needs additional time to complete the adjustments, notice should be provided within seven days prior to deadline. Upon providing good cause, staff should be given administrative authority to grant an extension of up to 60 days.

Issue 15: 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 outstanding Phase I pro forma items have been completed, the revised tariff sheets and customer notice have been filed by the utility and approved by staff, and the utility has provided staff with proof that the adjustments for all the applicable NARUC USOA primary accounts have been made. Also, the docket should remain open to allow staff to verify that the Phase II pro forma items have been completed, and the Phase II rates properly implemented. Once these actions are complete, this docket should be closed administratively. (Corbari, Mouring)

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 outstanding Phase I pro forma items have been completed, the revised tariff sheets and customer notice have been filed by the utility and approved by staff, and the utility has provided staff with proof that the adjustments for all applicable NARUC USOA primary accounts have been made. Also, the docket should remain open to allow staff to verify that the Phase II pro forma items have been completed and the Phase II rates properly implemented. Once these actions are complete, this docket should be closed administratively.

HOLIDAY GARDENS UTILITIES, LLC — **SCHEDULE NO. 1-A**
TEST YEAR ENDED 09/30/14 — **DOCKET NO. 140177-WU**
SCHEDULE OF WATER RATE BASE (PHASE I)

DESCRIPTION	BALANCE PER UTILITY	STAFF ADJUSTMENTS TO UTIL. BAL.	BALANCE PER STAFF
UTILITY PLANT IN SERVICE	$180,627	$9,646	$190,273
LAND & LAND RIGHTS	3,059	(645)	2,414
NON-USED AND USEFUL COMPONENTS	0	0	0
CIAC	(85,630)	0	(85,630)
ACCUMULATED DEPRECIATION	(162,118)	12,813	(149,305)
AMORTIZATION OF CIAC	85,630	0	85,630
WORKING CAPITAL ALLOWANCE	0	14,345	14,345
WATER RATE BASE	$21,568	$36,159	$57,727

HOLIDAY GARDENS UTILITIES, LLC TEST YEAR ENDED 09/30/14 ADJUSTMENTS TO RATE BASE (PHASE I)		SCHEDULE NO. 1-B DOCKET NO. 140177-WU
		WATER
	UTILITY PLANT IN SERVICE	
1.	To reflect the appropriate UPIS.	$413
2.	To include the purchase of shop tools.	250
3.	To reflect pro forma plant additions and retirements.	9,314
4.	To reflect the appropriate averaging adjustment.	(331)
	Total	$9,646
	LAND	
	To reflect the appropriate land balance.	($645)
	ACCUMULATED DEPRECIATION	
1.	To reflect the appropriate Accumulated Depreciation.	($1,954)
2.	To include the purchase of shop tools.	(25)
3.	To reflect pro forma plant additions and retirements.	13,815
4.	To reflect the appropriate averaging adjustment.	978
	Total	$12,813
	WORKING CAPITAL ALLOWANCE	
	To reflect 1/8 of test year O&M expenses.	$14,345

HOLIDAY GARDENS UTILITIES, LLC **SCHEDULE NO. 2**
TEST YEAR ENDED 09/30/14 **DOCKET NO. 140177-WU**
SCHEDULE OF CAPITAL STRUCTURE (PHASE I)

	CAPITAL COMPONENT	PER UTILITY	STAFF SPECIFIC ADJUST-MENTS	BALANCE BEFORE PRO RATA ADJUSTMENTS	PRO RATA ADJUST-MENTS	BALANCE PER STAFF	PERCENT OF TOTAL	COST	WEIGHTED COST
1.	COMMON EQUITY	$7,500	$0	$7,500	$4,761	$12,261	21.24%	11.16%	2.37%
2.	LONG-TERM DEBT	423,172	(398,628)	24,544	15,581	40,125	69.51%	7.50%	5.21%
3.	SHORT-TERM DEBT (Truck)	0	2,827	2,827	1,794	4,621	8.00%	5.00%	0.40%
4.	PREFERRED STOCK	0	0	0	0	0	0.00%	0.00%	0.00%
5.	CUSTOMER DEPOSITS	576	144	720	0	720	1.25%	2.00%	0.02%
6.	DEFERRED INCOME TAXES	0	0	0	0	0	0.00%	0.00%	0.00%
7.	TOTAL	$431,248	($395,657)	$35,591	$22,137	$57,727	100.00%		8.01%

RANGE OF REASONABLENESS	LOW	HIGH
RETURN ON EQUITY	10.16%	12.16%
OVERALL RATE OF RETURN	7.80%	8.22%

HOLIDAY GARDENS UTILITIES, LLC | **SCHEDULE NO. 3-A**
TEST YEAR ENDED 09/30/14 | **DOCKET NO. 140177-WU**
SCHEDULE OF WATER OPERATING INCOME (PHASE I)

		TEST YEAR PER UTILITY	STAFF ADJUSTMENTS	STAFF ADJUSTED TEST YEAR	ADJUST. FOR INCREASE	REVENUE REQUIREMENT
1.	**OPERATING REVENUES**	$77,847	$1,827	$79,674	$55,636	$135,310
					69.83%	
	OPERATING EXPENSES:					
2.	OPERATION & MAINTENANCE	$71,968	$42,795	$114,763	$0	$114,763
3.	DEPRECIATION (NET)	0	2,876	2,876	0	2,876
4.	TAXES OTHER THAN INCOME	6,061	4,483	10,544	2,504	13,048
5.	INCOME TAXES	0	0	0	0	0
6.	**TOTAL OPERATING EXPENSES**	$78,029	$50,154	$128,183	$2,504	$130,686
7.	**OPERATING INCOME/(LOSS)**	($182)		($48,509)		$4,624
8.	**WATER RATE BASE**	$21,568		$57,727		$57,727
9.	**RATE OF RETURN**	(0.84%)		(84.03%)		8.01%

HOLIDAY GARDENS UTILITIES, LLC **SCHEDULE NO. 3-B**
TEST YEAR ENDED 09/30/14 **DOCKET NO. 140177-WU**
ADJUSTMENTS TO OPERATING INCOME (PHASE I) **Page 1 of 2**

		WATER
	OPERATING REVENUES	
	a. To reflect the appropriate test year service revenues.	$1,657
	b. To reflect the test year miscellaneous service revenues.	152
	Subtotal	$1,827
	OPERATION AND MAINTENANCE EXPENSES	
1.	Salaries and Wages – Employees (601)	
	To reflect the appropriate amount of salary expense for the test year.	$32,113
2.	Salaries and Wages – Officers (603)	
	To reflect the appropriate amount of officer's salary expense for the test year.	$10,308
3.	Employee Pensions and Benefits (604)	
	To reflect the appropriate medical and workman's comp. benefits.	$5,171
4.	Material and Supplies (620)	
	To reflect capitalized items.	($1,902)
5.	Contractual Services - Other (636)	
	a. To remove out-of-period expenses.	($2,015)
	b. To reflect the reduction in lawn maintenance expense.	(540)
	Subtotal	($2,555)
6.	Rents (640)	
	To reflect the appropriate rent expense.	($1,940)
7.	Insurance Expense (655)	
	To reflect the appropriate insurance expense.	($1,716)
8.	Regulatory Commission Expense (665)	
	To reflect 4-year amortization of rate case expense.	$1,787
9.	Bad Debt Expense (670)	
	To reflect the 3-year average bad debt expense	$300
10.	Miscellaneous Expense (675)	
	a. To reflect the meter replacement program expense.	$3,043
	b. To reflect the licensing and corporations fees, and DEP Permit.	1,316
	c. To remove duplicate telephone and utilities expense.	(3,129)
	Subtotal	$1,229
	TOTAL OPERATION & MAINTENANCE ADJUSTMENTS	$42,795

(O&M EXPENSES CONTINUED ON NEXT PAGE)

HOLIDAY GARDENS UTILITIES, LLC TEST YEAR ENDED 09/30/14 ADJUSTMENTS TO OPERATING INCOME (PHASE I)	SCHEDULE NO. 3-B DOCKET NO. 140177-WU Page 2 of 2
DEPRECIATION EXPENSE	
To reflect appropriate depreciation expense per Rule 25-30.140 F.A.C..	$2,876
TAXES OTHER THAN INCOME	
a. To reflect the appropriate test year property taxes.	$37
b. To reflect the appropriate allocation of payroll taxes.	4,447
Total	$4,483

HOLIDAY GARDENS UTILITIES, LLC			SCHEDULE NO. 3-C
TEST YEAR ENDED 09/30/14			DOCKET NO. 140177-WU
ANALYSIS OF WATER OPERATION AND MAINTENANCE EXPENSE (PHASE I)			
	TOTAL PER UTILITY	STAFF ADJUST-MENTS	TOTAL PER STAFF
(601) SALARIES AND WAGES - EMPLOYEES	$20,091	$32,113	$52,204
(603) SALARIES AND WAGES - OFFICERS	1,455	10,308	11,763
(604) EMPLOYEE PENSIONS AND BENEFITS	777	5,171	5,948
(610) PURCHASED WATER	0	0	0
(615) PURCHASED POWER	3,260	0	3,260
(616) FUEL FOR POWER PRODUCTION	100	0	100
(618) CHEMICALS	2,179	0	2,179
(620) MATERIALS AND SUPPLIES	1,902	(1,902)	0
(630) CONTRACTUAL SERVICES - BILLING	0	0	0
(631) CONTRACTUAL SERVICES - PROFESSIONAL	0	0	0
(633) CONTRACTUAL SERVICES - LEGAL	0	0	0
(636) CONTRACTUAL SERVICES - OTHER	23,445	(2,555)	20,890
(640) RENTS	6,398	(1,940)	4,458
(650) TRANSPORTATION EXPENSE	763	0	763
(655) INSURANCE EXPENSE	4,784	(1,716)	3,068
(665) REGULATORY COMMISSION EXPENSE	0	1,787	1,787
(670) BAD DEBT EXPENSE	0	300	300
(675) MISCELLANEOUS EXPENSE	6,814	1,229	8,043
TOTAL WATER O&M EXPENSES	$71,968	$42,795	$114,763

HOLIDAY GARDENS UTILITIES, LLC.
TEST YEAR ENDED SEPTEMBER 30, 2014
MONTHLY WATER RATES (PHASE I)

SCHEDULE NO. 4
DOCKET NO. 140177-WU

	RATES AT TIME OF FILING	STAFF RECOMMENDED RATES	4 YEAR RATE REDUCTION
Residential and General Service			
Base Facility Charge by Meter Size			
5/8" x 3/4"	$7.64	$9.97	$0.15
3/4"	$11.45	$14.96	$0.22
1"	$19.14	$24.93	$0.37
1-1/2"	$38.23	$49.85	$0.73
2"	$61.22	$79.76	$1.17
3"	$122.45	$159.52	$2.35
4"	$191.29	$249.25	$3.67
6"	$382.59	$498.50	$7.34
Charge per 1,000 gallons - Residential	$1.35	N/A	N/A
0 - 3,000 gallons	N/A	$3.26	$0.05
Over 3,000 gallons	N/A	$5.16	$0.08
Charge per 1,000 gallons - General Service	$1.35	$3.91	$0.06
Typical Residential 5/8" x 3/4" Meter Bill Comparison			
3,000 Gallons	$13.04	$24.91	
6,000 Gallons	$15.74	$35.23	
10,000 Gallons	$21.14	$55.87	

HOLIDAY GARDENS UTILITIES, LLC **SCHEDULE NO. 5-A**
TEST YEAR ENDED 09/30/14 **DOCKET NO. 140177-WU**
SCHEDULE OF WATER RATE BASE (PHASE II)

DESCRIPTION	PHASE I BALANCE	STAFF ADJUSTMENTS TO UTIL. BAL.	BALANCE PER STAFF
UTILITY PLANT IN SERVICE	$190,273	$4,749	$195,021
LAND & LAND RIGHTS	2,414	0	2,414
NON-USED AND USEFUL COMPONENTS	0	0	0
CIAC	(85,630)	0	(85,630)
ACCUMULATED DEPRECIATION	(149,305)	11,208	(138,097)
AMORTIZATION OF CIAC	85,630	0	85,630
WORKING CAPITAL ALLOWANCE	14,345	0	14,345
WATER RATE BASE	$57,727	$15,957	$73,684

HOLIDAY GARDENS UTILITIES, LLC TEST YEAR ENDED 09/30/14 ADJUSTMENTS TO RATE BASE (PHASE II)	SCHEDULE NO. 5-B DOCKET NO. 140177-WU
	WATER
UTILITY PLANT IN SERVICE	
To reflect pro forma plant additions and retirements.	$4,749
ACCUMULATED DEPRECIATION	
To reflect pro forma plant additions and retirements.	$11,208

HOLIDAY GARDENS UTILITIES, LLC **SCHEDULE NO. 6**
TEST YEAR ENDED 09/30/14 **DOCKET NO. 140177-WU**
SCHEDULE OF CAPITAL STRUCTURE (PHASE II)

	CAPITAL COMPONENT	PHASE I BALANCE	STAFF SPECIFIC ADJUST-MENTS	BALANCE BEFORE PRO RATA ADJUSTMENTS	PRO RATA ADJUST-MENTS	BALANCE PER STAFF	PERCENT OF TOTAL	COST	WEIGHTED COST
1.	COMMON EQUITY	$7,500	$0	$7,500	$8,193	$15,693	21.30%	11.16%	2.38%
2.	LONG-TERM DEBT	24,544	0	24,544	26,812	51,356	69.70%	7.50%	5.23%
3.	SHORT-TERM DEBT (Truck)	2,827	0	2,827	3,088	5,914	8.03%	5.00%	0.40%
4.	PREFERRED STOCK	0	0	0	0	0	0.00%	0.00%	0.00%
5.	CUSTOMER DEPOSITS	720	0	720	0	720	0.98%	2.00%	0.02%
6.	DEFERRED INCOME TAXES	0	0	0	0	0	0.00%	0.00%	0.00%
7.	TOTAL	$35,591	$0	$35,591	$38,093	$73,684	100.00%		8.03%

RANGE OF REASONABLENESS	LOW	HIGH
RETURN ON EQUITY	10.16%	12.16%
OVERALL RATE OF RETURN	7.81%	8.24%

HOLIDAY GARDENS UTILITIES, LLC **SCHEDULE NO. 7-A**
TEST YEAR ENDED 09/30/14 **DOCKET NO. 140177-WU**
SCHEDULE OF WATER OPERATING INCOME (PHASE II)

		PHASE I	STAFF ADJUSTMENTS	STAFF ADJUSTED TEST YEAR	ADJUST. FOR INCREASE	REVENUE REQUIREMENT
1.	**OPERATING REVENUES**	$135,310	$0	$135,310	$1,603	$136,913
					1.18%	
	OPERATING EXPENSES:					
2.	OPERATION & MAINTENANCE	$114,763	$0	$114,763	$0	$114,763
3.	DEPRECIATION (NET)	2,876	238	3,114	0	3,114
4.	TAXES OTHER THAN INCOME	13,048	0	13,048	72	13,120
5.	INCOME TAXES	0	0	0	0	0
6.	**TOTAL OPERATING EXPENSES**	$130,686	$238	$130,925	$72	$130,997
7.	**OPERATING INCOME/(LOSS)**	$4,624		$4,386		$5,917
8.	**WATER RATE BASE**	$57,727		$73,684		$73,684
9.	**RATE OF RETURN**	8.01%		5.95%		8.03%

HOLIDAY GARDENS UTILITIES, LLC TEST YEAR ENDED 09/30/14 ADJUSTMENTS TO OPERATING INCOME (PHASE II)	SCHEDULE NO. 7-B DOCKET NO. 140177-WU
	WATER
DEPRECIATION EXPENSE	
To reflect appropriate depreciation expense per Rule 25-30.140 F.A.C..	$238

HOLIDAY GARDENS UTILITIES, LLC **SCHEDULE NO. 8**
TEST YEAR ENDED SEPTEMBER 30, 2014 **DOCKET NO. 140177-WU**
MONTHLY WATER RATES (PHASE II)

	RATES AT TIME OF FILING	STAFF RECOMMENDED RATES
Residential and General Service		
Base Facility Charge by Meter Size		
5/8" x 3/4"	$9.97	$10.09
3/4"	$14.96	$15.14
1"	$24.93	$25.23
1-1/2"	$49.85	$50.45
2"	$79.76	$80.72
3"	$159.52	$161.44
4"	$249.25	$252.25
6"	$498.50	$504.50
Charge per 1,000 gallons - Residential	N/A	N/A
0 - 3,000 gallons	$3.26	$3.30
Over 3,000 gallons	$5.16	$5.22
Charge per 1,000 gallons - General Service	$3.91	$3.96
Typical Residential 5/8" x 3/4" Meter Bill Comparison		
3,000 Gallons	$24.91	$25.21
5,000 Gallons	$35.23	$35.65
10,000 Gallons	$55.87	$56.53

Item 7

FILED NOV 18, 2015
DOCUMENT NO. 07301-15
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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (Frank, Norris)
Office of the General Counsel (Villafrate)

AM BG CR ALM JSC DF

RE: Docket No. 150005-WS – 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.

AGENDA: 12/3/15 – Regular Agenda – Proposed Agency Action - Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 03/31/16

SPECIAL INSTRUCTIONS: None

Case Background

Since March 31, 1981, pursuant to the guidelines established by Section 367.081(4)(a), Florida Statutes (F.S.), and Rule 25-30.420, Florida Administrative Code (F.A.C.), the Commission has established a price index increase or decrease for major categories of operating costs on or before March 31 of each year. This process allows water and wastewater utilities to adjust rates based on current specific expenses without applying for a rate case.

Staff has calculated its proposed 2016 price index by comparing the Gross Domestic Product Implicit Price Deflator Index for the fiscal year ended September 30, 2014, to the same index, for the fiscal year ended September 30, 2015. This same procedure has been used each year since 1995 to calculate the price index. The U.S. Department of Commerce, Bureau of Economic Analysis, released its most recent third quarter figures on October 29, 2015.

Since March 31, 1981, the Commission has received and processed approximately 3,499 index applications. The Commission has jurisdiction over this matter pursuant to Section 367.081, F.S.

Discussion of Issues

Issue 1: Which index should be used to determine price level adjustments?

Recommendation: The Gross Domestic Product Implicit Price Deflator Index is recommended for use in calculating price level adjustments. Staff recommends calculating the 2016 price index by using a fiscal year, four quarter comparison of the Implicit Price Deflator Index ending with the third quarter 2015. (Frank)

Staff Analysis: In 1993, the Gross Domestic Product Implicit Price Deflator Index (GDP) was established as the appropriate measure for determining the water and wastewater price index. At this same time, the convention of using a four quarter fiscal year comparison was also established and this practice has been used every year since then.[1] The GDP is prepared by the U.S. Department of Commerce. Prior to that time, the Gross National Product Implicit Price Deflator Index (GNP) was used as the indexing factor for water and wastewater utilities. The Department of Commerce switched its emphasis from the GNP to the GDP as the primary measure of U.S. production.

Pursuant to Section 367.081(4)(a), F.S., the Commission, by order, shall establish a price increase or decrease index for major categories of operating costs incurred by utilities subject to its jurisdiction reflecting the percentage of increase or decrease in such costs from the most recent 12-month historical data available. Since 1995, the price index was determined by using a four quarter comparison, ending September 30, of the Implicit Price Deflator Index in order to meet the statutory deadline. The current price index was determined by comparing the change in the GDP using the four quarter fiscal year comparison ending September 30. This method has been used consistently since 1995 to determine the price index.[2]

In Order No. PSC-15-0072-PAA-WS, issued January 27, 2015, in Docket No. 150005-WS, the Commission, in keeping with the practice started in 1993, reiterated the alternatives which could be used to calculate the indexing of utility revenues. Past concerns expressed by utilities, as summarized from utility input in previous hearings, are:

1) Inflation should be a major factor in determining the index;

2) Nationally published indices should be vital to this determination;

3) Major categories of expenses are labor, chemicals, sludge-hauling, materials and supplies, maintenance, transportation, and treatment expense;

4) An area wage survey, Dodge Building Cost Index, Consumer Price Index, and the GDP should be considered;

5) A broad measure index should be used; and

[1] Order No. PSC-93-0195-FOF-WS, issued February 9, 1993, in Docket No. 930005-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.*

[2] Order No. PSC-95-0202-FOF-WS, issued February 10, 1995, in Docket No. 950005-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.*

6) The index procedure should be easy to administer.

Based upon these concerns, the Commission has previously explored the following alternatives:

1) Survey of Regulated Water and Wastewater Utilities;

2) Consumer Price Index;

3) Florida Price Level Index;

4) Producer's Price Index - previously the Wholesale Price Index; and

5) GDP (replacing the GNP).

Over the past years, the Commission found that the Survey of Regulated Water and Wastewater Utilities should be rejected because using the results of a survey would allow utilities to pass on to customers all cost increases, thereby reducing the incentives of promoting efficiency and productivity. The Commission has also found that the Consumer Price Index and the Florida Price Level Index should be rejected because of their limited degree of applicability to the water and wastewater industry. Both of these price indices are based upon comparing the advance in prices of a limited number of general goods and, therefore, appear to have limited application to water and wastewater utilities.

The Commission further found that the Producers Price Index (PPI) is a family of indices that measures the average change over time in selling prices received by domestic producers of goods and services. PPI measures price change from the perspective of the seller, not the purchaser, and therefore should be rejected. Because the bases for these indices have not changed, staff believes that the conclusions reached in Order No. PSC-15-0072-PAA-WS should continue to apply in this case. Since 1993, the Commission has found that the GDP has a greater degree of applicability to the water and wastewater industry. Therefore, staff recommends that the Commission continue to use the GDP to calculate water and wastewater price level adjustments.

The following information provides a historical perspective of the annual price index:

Table 1-1
Historical Analysis of the Annual Price Index for Water and Wastewater Utilities

Year	Commission Approved Index	Year	Commission Approved Index
2004	1.60%	2010	0.56%
2005	2.17%	2011	1.18%
2006	2.74%	2012	2.41%
2007	3.09%	2013	1.63%
2008	2.39%	2014	1.41%
2009	2.55%	2015	1.57%

The table below shows the historical participation in the Index and/or Pass-Through programs:

Table 1-2
Percentage of Jurisdictional Water and Wastewater Utilities Filing for Indexes and/or Pass-Throughs

Year	Percentage	Year	Percentage
2004	22%	2010	29%
2005	33%	2011	43%
2006	32%	2012	30%
2007	47%	2013	41%
2008	42%	2014	39%
2009	53%	2015	49%

Issue 2: What rate should be used by water and wastewater utilities for the 2016 Price Index?

Recommendation: The 2016 Price Index for water and wastewater utilities should be 1.29 percent. (Frank)

Staff Analysis: The U.S. Department of Commerce, Bureau of Economic Analysis, released the most recent third quarter 2014 figures on October 29, 2015. This year staff is using the October 29, 2015 release instead of the release issued in late December when the 3rd quarter GDP Index is updated. The reason for this is to allow time for a hearing if there is a protest, in order for the Commission to establish the 2016 Price Index by March 31, 2016, in accordance with Section 367.081(4)(a), F.S. The percentage change in the GDP using the fiscal year comparison ending with the third quarter is 1.29 percent. This number was calculated as follows:

GDP Index for the fiscal year ended 9/30/15	110.007
GDP Index for the fiscal year ended 9/30/14	108.603
Difference	1.40
Divided by 9/30/14 GDP Index	108.603
2016 Price Index	1.29%

Issue 3: How should the utilities be informed of the indexing requirements?

Recommendation: Pursuant to Rule 25-30.420(1), F.A.C., the Office of Commission Clerk, after the expiration of the Proposed Agency Action (PAA) protest period, should mail each regulated water and wastewater utility a copy of the PAA order establishing the index containing the information presented in Form PSC/ECR 15 (4/99) and Appendix A (Attachment 1). A cover letter from the Director of the Division of Accounting and Finance should be included with the mailing of the order (Attachment 2). The entire package will also be made available on the Commission's website. (Frank)

Staff Analysis: Staff designed a package (Form PSC/ECR 15 (4/99) and Appendix A), attached hereto as Attachment 1, that details the requirements of the Commission's Index and Pass-Through programs. This package has significantly reduced the number of questions regarding what the index and pass-through rate adjustments are, how to apply for an adjustment, and what needs to be filed to meet the filing requirements.

Staff recommends that the package presented in Form PSC/ECR 15 (4/99) and Appendix A (Attachment 1) be mailed to every regulated water and wastewater utility after the expiration of the PAA protest period, along with a copy of the PAA order that has become final. The entire package will also be made available on the Commission's website.

In an effort to increase the number of water and wastewater utilities taking advantage of the annual price index and pass-through programs, staff is recommending that the attached cover letter (Attachment 2) from the Director of the Division of Accounting and Finance be included with the mailing of the PAA Order to explain the purpose of the index and pass-through applications and that Commission staff is available to assist them.

Issue 4: Should this docket be closed?

Recommendation: No. Upon expiration of the 14-day protest period, if a timely protest is not received, the decision should become final and effective upon the issuance of a Consummating Order. Any party filing a protest should be required to prefile testimony with the protest. However, this docket should remain open through the end of the year and be closed upon the establishment of the new docket on January 4, 2016. (Villafrate, Frank)

Staff Analysis: Uniform Rule 25-22.029(1), F.A.C., contains an exception to the procedural requirements set forth in Uniform Rule 28-106.111, F.A.C., providing that "[t]he time for requesting a Section 120.569 or 120.57 hearing shall be 14 days from issuance of the notice for PAA orders establishing a price index pursuant to Section 367.081(4)(a), F.S." Therefore, staff recommends that the Commission require any protest to the PAA Order in this docket be filed within 14 days of the issuance of the PAA Order, and that any party filing the protest should be required to prefile testimony with the protest. Upon expiration of the protest period, if a timely protest is not received, the decision should become final and effective upon the issuance of a Consummating Order. However, this docket should remain open through the end of the year and be closed upon the establishment of the new docket on January 4, 2016.

FLORIDA PUBLIC SERVICE COMMISSION
2016 PRICE INDEX APPLICATION
TEST YEAR ENDED DECEMBER 31, 2015

	WATER	WASTEWATER
DEP PWS ID NO. ________________		
DEP WWTP ID NO. _______________		
*2015 Operation and Maintenance Expenses	$	$
LESS:		
(a) Pass-through Items:		
(1) Purchased Power		
(2) Purchased Water		
** (3) Purchased Wastewater Treatment		
***(4) New DEP Required Water Testing		
***(5) New DEP Required Wastewater Testing		
(6) NPDES Fees		
(b) Rate Case Expense Included in 2015 Expenses		
(c) Adjustments to O & M Expenses from last rate case, if applicable:		
(1)		
(2)	________	________
Costs to be Indexed	$	$
Multiply by change in GDP Implicit Price Deflator Index	.0129	.0129
Indexed Costs	$	$
**** Add Change in Pass-Through Items:		
(1)		
(2)		
Divide Index and Pass-Through Sum by Expansion Factor for Regulatory Assessment Fees	.955	.955
Increase in Revenue	$	$
***** Divide by 2015 Revenue	__________	__________
Percentage Increase in Rates	%	%
	=========	=========

EXPLANATORY NOTES APPEAR ON THE FOLLOWING PAGE

PSC/ECR 15 (04/99)

PAGE 1 NOTES

* This amount must match 2015 annual report.

** This may include government-mandated disposal fees.

*** Daily, weekly, or monthly testing required by the Department of Environmental Protection (DEP) not currently included in the utility's rates. Or additional tests required by the DEP during the 12-month period prior to filing by the utility and/or changes to the frequency of existing test(s) required by the DEP during the 12-month period prior to filing by the utility.

**** This may include an increase in purchased power, purchased water, purchased wastewater treatment, required DEP testing, and ad valorem taxes, providing that those increases have been incurred within the 12-month period prior to the submission of the pass-through application. Pass-through NPDES fees and increases in regulatory assessment fees are eligible as pass-through costs but not subject to the twelve month rule. DEP water and wastewater testing pass-throughs require invoices. See Rule 25-30.425, F.A.C. for more information.

***** If rates changed after January 1, 2015, the book revenues must be adjusted to show the changes and an explanation of the calculation should be attached to this form. See Annualized Revenue Worksheet for instructions and a sample format.

ANNUALIZED REVENUE WORKSHEET

Have the rates charged for customer services changed since January 1, 2015?

( ) If no, the utility should use actual revenues. This form may be disregarded.

( ) If yes, the utility must annualize its revenues. Read the remainder of this form.

Annualizing calculates the revenues the utility would have earned based upon 2015 customer consumption at the most current rates in effect. To complete this calculation, the utility will need consumption data for 2015 to apply to the existing rate schedule. Below is a sample format which may be used.

CALCULATION OF ANNUALIZED REVENUES*
Consumption Data for 2015

	Number of Bill/Gal. Sold	X	Current Rates	Annualized Revenues
Residential Service:				
Bills: 5/8"x3/4" meters	. . . .		. . . .	. . . .
1" meters	. . . .		. . . .	. . . .
1 ½" meters	. . . .		. . . .	. . . .
2" meters	. . . .		. . . .	. . . .
Gallons Sold	. . . .		. . . .	. . . .
General Service:				
Bills: 5/8"x3/4" meters	. . . .		. . . .	. . . .
1" meters	. . . .		. . . .	. . . .
1 ½" meters	. . . .		. . . .	. . . .
2" meters	. . . .		. . . .	. . . .
3" meters	. . . .		. . . .	. . . .
4" meters	. . . .		. . . .	. . . .
6" meters	. . . .		. . . .	. . . .
Gallons Sold	. . . .		. . . .	. . . .

Total Annualized Revenues for 2015 $

* Annualized revenues must be calculated separately if the utility consists of both a water system and a wastewater system. This form is designed specifically for utilities using a base facility charge rate structure. If annualized revenues must be calculated and further assistance is needed, contact the Commission Staff at (850) 413-6900.

Appendix A

PRICE INDEX ADJUSTMENTS IN RATES

Section 367.081(4)(a), (c), (d), (e), and (f) Florida Statutes
Rule 25-30.420, Florida Administrative Code
Sample Affirmation Affidavit
Notice to Customers

Sections 367.081(4)(a), (c), (d), (e), and (f), Florida Statutes

(4)(a) On or before March 31 of each year, the commission by order shall establish a price increase or decrease index for major categories of operating costs incurred by utilities subject to its jurisdiction reflecting the percentage of increase or decrease in such costs from the most recent 12-month historical data available. The commission by rule shall establish the procedure to be used in determining such indices and a procedure by which a utility, without further action by the commission, or the commission on its own motion, may implement an increase or decrease in its rates based upon the application of the indices to the amount of the major categories of operating costs incurred by the utility during the immediately preceding calendar year, except to the extent of any disallowances or adjustments for those expenses of that utility in its most recent rate proceeding before the commission. The rules shall provide that, upon a finding of good cause, including inadequate service, the commission may order a utility to refrain from implementing a rate increase hereunder unless implemented under a bond or corporate undertaking in the same manner as interim rates may be implemented under s. 367.082. A utility may not use this procedure between the official filing date of the rate proceeding and 1 year thereafter, unless the case is completed or terminated at an earlier date. A utility may not use this procedure to increase any operating cost for which an adjustment has been or could be made under paragraph (b), or to increase its rates by application of a price index other than the most recent price index authorized by the commission at the time of filing.

(c) Before implementing a change in rates under this subsection, the utility shall file an affirmation under oath as to the accuracy of the figures and calculations upon which the change in rates is based, stating that the change will not cause the utility to exceed the range of its last authorized rate of return on equity. Whoever makes a false statement in the affirmation required hereunder, which statement he or she does not believe to be true in regard to any material matter, is guilty of a felony of the third degree, punishable as provided in s. 775.082, s. 775.083, or s. 775.084.

(d) If, within 15 months after the filing of a utility's annual report required by s. 367.121, the commission finds that the utility exceeded the range of its last authorized rate of return on equity after an adjustment in rates as authorized by this subsection was implemented within the year for which the report was filed or was implemented in the preceding year, the commission may order the utility to refund, with interest, the difference to the ratepayers and adjust rates accordingly. This provision shall not be construed to require a bond or corporate undertaking not otherwise required.

(e) Notwithstanding anything herein to the contrary, a utility may not adjust its rates under this subsection more than two times in any 12-month period. For the purpose of this paragraph, a combined application or simultaneously filed applications that were filed under the provisions of paragraphs (a) and (b) shall be considered one rate adjustment.

(f) The commission may regularly, not less often than once each year, establish by order a leverage formula or formulae that reasonably reflect the range of returns on common equity for an average water or wastewater utility and which, for purposes of this section, shall be used to calculate the last authorized rate of return on equity for any utility which otherwise would have no established rate of return on equity. In any other proceeding in which an authorized rate of return on equity is to be established, a utility, in lieu of presenting evidence on its rate of return on common equity, may move the commission to adopt the range of rates of return on common equity that has been established under this paragraph.

25-30.420 Establishment of Price Index, Adjustment of Rates; Requirement of Bond; Filings After Adjustment; Notice to Customers.

(1) The Commission shall, on or before March 31 of each year, establish a price increase or decrease index as required by section 367.081(4)(a), F.S. The Division of the Commission Clerk and Administrative Services shall mail each regulated water and wastewater utility a copy of the proposed agency action order establishing the index for the year and a copy of the application. Form PSC/ECR 15 (04/99), entitled "Index Application", is incorporated into this rule by reference and may be obtained from the Commission's Division of Economic Regulation. Applications for the newly established price index will be accepted from April 1 of the year the index is established through March 31 of the following year.
(a) The index shall be applied to all operation and maintenance expenses, except for amortization of rate case expense, costs subject to pass-through adjustments pursuant to section 367.081(4)(b), F.S., and adjustments or disallowances made in a utility's most recent rate proceeding.
(b) In establishing the price index, the Commission will consider cost statistics compiled by government agencies or bodies, cost data supplied by utility companies or other interested parties, and applicable wage and price guidelines.
(2) Any utility seeking to increase or decrease its rates based upon the application of the index established pursuant to subsection (1) and as authorized by section 367.081(4)(a), F.S., shall file an original and five copies of a notice of intention and the materials listed in (a) through (i) below with the Commission's Division of Economic Regulation at least 60 days prior to the effective date of the increase or decrease. The adjustment in rates shall take effect on the date specified in the notice of intention unless the Commission finds that the notice of intention or accompanying materials do not comply with the law, or the rules or orders of the Commission. The notice shall be accompanied by:
(a) Revised tariff sheets;
(b) A computation schedule showing the increase or decrease in annual revenue that will result when the index is applied;
(c) The affirmation required by section 367.081(4)(c), F.S.;
(d) A copy of the notice to customers required by subsection (6);
(e) The rate of return on equity that the utility is affirming it will not exceed pursuant to section 367.081(4)(c), F.S.;
(f) An annualized revenue figure for the test year used in the index calculation reflecting the rate change, along with an explanation of the calculation, if there has been any change in the utility's rates during or subsequent to the test year;
(g) The utility's Department of Environmental Protection Public Water System identification number and Wastewater Treatment Plant Operating Permit number.
(h) A statement that the utility does not have any active written complaints, corrective orders, consent orders, or outstanding citations with the Department of Environmental Protection (DEP) or the County Health Department(s) or that the utility does have active written complaints, corrective orders, consent orders, or outstanding citations with the DEP or the County Health Department(s).
(i) A copy of any active written complaints, corrective orders, consent orders, or outstanding citations with the Department of Environmental Protection (DEP) or the County Health Department(s).
(3) If the Commission, upon its own motion, implements an increase or decrease in the rates of a utility based upon the application of the index established pursuant to subsection (1) and as authorized by section 367.081(4)(a), F.S., the Commission will require a utility to file the information required in subsection (2).

(4) Upon a finding of good cause, the Commission may require that a rate increase pursuant to section 367.081(4)(a), F.S., be implemented under a bond or corporate undertaking in the same manner as interim rates. For purposes of this subsection, "good cause" shall include:

(a) Inadequate service by the utility;

(b) Inadequate record-keeping by the utility such that the Commission is unable to determine whether the utility is entitled to implement the rate increase or decrease under this rule.

(5) Prior to the time a customer begins consumption at the rates established by application of the index, the utility shall notify each customer of the increase or decrease authorized and explain the reasons therefore.

(6) No utility shall file a notice of intention pursuant to this rule unless the utility has on file with the Commission an annual report as required by Rule 25-30.110(3), F.A.C., for the test year specified in the order establishing the index for the year.

(7) No utility shall implement a rate increase pursuant to this rule within one year of the official date that it filed a rate proceeding, unless the rate proceeding has been completed or terminated.

Specific Authority: 350.127(2), 367.081(4)(a), 367.121(1)(c), 367.121(1)(f), F.S. Law Implemented: 367.081(4), 367.121(1)(c), 367.121(1)(g), F.S. History: New 04/05/81, Amended 09/16/82, Formerly 25-10.185, Amended 11/10/86, 06/05/91, 04/18/99, 12/12/03.

AFFIRMATION

I, ____________________________________, hereby affirm that the figures and calculations upon which the change in rates is based are accurate and that the change will not cause ________________________________ to exceed the range of its last
(Utility Name)
authorized rate of return on equity, which is ___________________.

I, the undersigned/officer of the above-named utility, have read the foregoing and declare that, to the best of my knowledge and belief, the information contained in this application is true and correct.

This affirmation is made pursuant to my request for a 2016 price index and/or pass-through rate increase, in conformance with Section 367.081(4)(c), Florida Statutes.

Further, I am aware that pursuant to Section 837.06, Florida Statutes, whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree.

Signature: _________________________
Title: ____________________________
Telephone Number: ________________
Fax Number: _______________________

Sworn to and subscribed before me this _________________________day of ____________________, 20__.

My Commission expires:

(SEAL)

____
Notary Public
State of Florida

STATEMENT OF QUALITY OF SERVICE

Pursuant to Rule 25-30.420(2)(h) and (i), Florida Administrative Code,
________________________________.
(Utility Name)

[ ] does not have any active written complaints, corrective orders, consent orders, or outstanding citations with the Department of Environmental Protection (DEP) or the County Health Departments.

[ ] does have the attached active written complaint(s), corrective order(s), consent order(s), or outstanding citation(s) with the DEP or the County Health Department(s). The attachment(s) includes the specific system(s) involved with DEP permit number and the nature of the active complaint, corrective order, consent order, or outstanding citation.

This statement is intended such that the Florida Public Service Commission can make a determination of quality of service pursuant to Section 367.081(4)(a), Florida Statutes, and Rule 25-30.420(4)(a), Florida Administrative Code.

Name: ______________________________
Title: ______________________________
Telephone Number: ___________________
Fax Number: _________________________
Date: ______________________________

NOTICE TO CUSTOMERS

Pursuant to Section 367.081(4)(a), Florida Statutes, water and wastewater utilities are permitted to adjust the rates and charges to its customers without those customers bearing the additional expense of a public hearing. These adjustments in rates would depend on increases or decreases in noncontrollable expenses subject to inflationary pressures such as chemicals, and other general operation and maintenance costs.

On ________________________, _____________________________________
(date) (name of company)

filed its notice of intention with the Florida Public Service Commission to increase water and wastewater rates in ______________ County pursuant to this Statute. The filing is subject to review by the Commission Staff for accuracy and completeness. Water rates will increase by approximately ______% and wastewater rates by ______%. These rates should be reflected for service rendered on or after ______________________.(date)

PASS-THROUGH RATE ADJUSTMENTS IN RATES

Section 367.081(4)(b), Florida Statutes
Rule 25-30.425, Florida Administrative Code
Waiver Form
Sample Affirmation Affidavit
Notice to Customers

Section 367.081(4)(b), Florida Statutes

(b) The approved rates of any utility which receives all or any portion of its utility service from a governmental authority or from a water or wastewater utility regulated by the commission and which redistributes that service to its utility customers shall be automatically increased or decreased without hearing, upon verified notice to the commission 45 days prior to its implementation of the increase or decrease that the rates charged by the governmental authority or other utility have changed. The approved rates of any utility which is subject to an increase or decrease in the rates or fees that it is charged for electric power, the amount of ad valorem taxes assessed against its used and useful property, the fees charged by the Department of Environmental Protection in connection with the National Pollutant Discharge Elimination System Program, or the regulatory assessment fees imposed upon it by the commission shall be increased or decreased by the utility, without action by the commission, upon verified notice to the commission 45 days prior to its implementation of the increase or decrease that the rates charged by the supplier of the electric power or the taxes imposed by the governmental authority, or the regulatory assessment fees imposed upon it by the commission have changed. The new rates authorized shall reflect the amount of the change of the ad valorem taxes or rates imposed upon the utility by the governmental authority, other utility, or supplier of electric power, or the regulatory assessment fees imposed upon it by the commission. The approved rates of any utility shall be automatically increased, without hearing, upon verified notice to the commission 45 days prior to implementation of the increase that costs have been incurred for water quality or wastewater quality testing required by the Department of Environmental Protection. The new rates authorized shall reflect, on an amortized basis, the cost of, or the amount of change in the cost of, required water quality or wastewater quality testing performed by laboratories approved by the Department of Environmental Protection for that purpose. The new rates, however, shall not reflect the costs of any required water quality or wastewater quality testing already included in a utility's rates. A utility may not use this procedure to increase its rates as a result of water quality or wastewater quality testing or an increase in the cost of purchased water services, sewer services, or electric power or in assessed ad valorem taxes, which increase was initiated more than 12 months before the filing by the utility. The provisions of this subsection do not prevent a utility from seeking a change in rates pursuant to the provisions of subsection (2).

25-30.425 Pass Through Rate Adjustment.

The verified notice to the Commission of an adjustment of rates under the provisions of Section 367.081(4)(b), F.S., shall be made in the following manner:
(1) Prior to an adjustment in rates because of an increase or decrease in purchased utility service, the utility shall file:
(a) A certified copy of the order, ordinance or other evidence whereby the rates for utility service are increased or decreased by the governmental agency or by a water or wastewater utility regulated by the Commission, along with evidence of the utility service rates of that governmental agency or water or wastewater utility in effect on January 1 of each of the three preceding years.
(b) A statement setting out by month the charges for utility services purchased from the governmental agency or regulated utility for the most recent 12-month period.
(c) 1. A statement setting out by month the gallons of water or wastewater treatment purchased from the governmental agency or regulated utility for the most recent 12-month period. If wastewater treatment service is not based on a metered flow, the number of units by which the service is measured shall be stated.
2. A statement setting out by month gallons of water and units of wastewater service sold by the utility for the most recent 12-month period.
(d) A statement setting out by month the gallons of water or wastewater treatment purchased from any other government entity or utility company.
(e) A statement setting out by month the gallons of water pumped or wastewater treated by the utility filing the verified notice.
(f) If the total water available for sale is in excess of 110% of the water sold, a statement explaining the unaccounted for water.
(2) Prior to an adjustment in rates because of an increase or decrease in the charge for electric power the utility shall file with the Commission:
(a) A certified copy of the order, ordinance or other evidence which establishes that the rates for electric power have been increased or decreased by the supplier, along with evidence of the electric power rates of the supplier in effect on January 1 of each of the three preceding years.
(b) A schedule showing, by month, the charges for electric power and consumption for the most recent 12 month period, the charges that would have resulted had the new electric rates been applied, and the difference between the charges under the old rates and the charges under the new rates.
(c) A statement outlining the measures taken by the utility to conserve electricity.
(3) Prior to an adjustment in rates because of an increase or decrease in ad valorem taxes the utility shall file with the Commission:
(a) A copy of the ad valorem tax bills which increased or decreased and copies of the previous three years' bills; if copies have been submitted previously, a schedule showing the tax total only is acceptable; and
(b) A calculation of the amount of the ad valorem taxes related to that portion of the water or wastewater plant not used and useful in providing utility service.
(4) Prior to an adjustment in rates because of an increase or decrease in the costs of water quality or wastewater quality testing required by the Department of Environmental Protection (DEP), or because of an increase or decrease in the fees charged by DEP in connection with the National Pollutant Discharge Elimination System Program, the utility shall file with the Commission:
(a) A copy of the invoice for testing;
(b) Calculation of the amortized amount.
(5) In addition to subsections (1), (2), (3), and (4) above, the utility shall also file:
(a) A schedule of proposed rates which will pass the increased or decreased costs on to the customers in a fair and nondiscriminatory manner and on the basis of current customers, and a calculation showing how the rates were determined;

(b) A statement, by class of customer and meter size, setting out by month the gallons of water and units of wastewater service sold by the utility for the most recent 12 month period. This statement shall not be required in filings for the pass through of increased regulatory assessment fees or ad valorem taxes;
(c) The affirmation reflecting the authorized rate of return on equity required by Section 367.081(4)(c), F.S.;
(d) A copy of the notice to customers required by subsection (7) of this rule;
(e) Revised tariff sheets reflecting the increased rates;
(f) The rate of return on equity that the utility is affirming it will not exceed pursuant to Section 367.081(4)(c), F.S.; and
(g) The utility's DEP Public Water System identification number and Wastewater Treatment Plant Operating Permit number;
(6) The amount authorized for pass through rate adjustments shall not exceed the actual cost incurred and shall not exceed the incremental increase or decrease for the 12-month period. Foregone pass through decreases shall not be used to adjust a pass through increase below the actual cost incurred.
(7) In order for the Commission to determine whether a utility which had adjusted its rates pursuant to Section 367.081(4)(b), F.S., has thereby exceeded the range of its last authorized rate of return, the Commission may require a utility to file the information required in Rule 25- 30.437, F. A. C., for the test year specified.
(8) Prior to the time a customer begins consumption at the adjusted rates, the utility shall notify each customer of the increase authorized and explain the reasons for the increase.
(9) The utility shall file an original and five copies of the verified notice and supporting documents with the Division of Economic Regulation. The rates shall become effective 45 days after the official date of filing. The official date of filing for the verified notice to the Commission of adjustment in rates shall be at least 45 days before the new rates are implemented.

Specific Authority 350.127(2), 367.121(1)(c), (f) FS. Law Implemented 367.081(4), 367.121(1)(c), (g) FS. History-New 6-10-75, Amended 4-5-79, 4-5-81, 10-21-82, Formerly 25-10.179, Amended 11-10-86, 6-5-91, 4-18-99.

WAIVER

____ hereby waives the right to implement a pass-through rate increase within 45 days of filing, as provided by Section 367.081(4)(b), Florida Statutes, in order that the pass-through and index rate increase may both be implemented together 60 days after the official filing date of this notice of intention.

Signature: ____________________________

Title: ________________________________

(To be used if an index and pass-through rate increase are requested jointly.)

AFFIRMATION

I, ______________________________________, hereby affirm that the figures and calculations upon which the change in rates is based are accurate and that the change will not cause __________________________________ to exceed the range of its last
(Utility Name)
authorized rate of return on equity, which is ____________________.

I, the undersigned/officer of the above-named utility, have read the foregoing and declare that, to the best of my knowledge and belief, the information contained in this application is true and correct.

This affirmation is made pursuant to my request for a 2016 price index and/or pass-through rate increase, in conformance with Section 367.081(4)(c), Florida Statutes.

Further, I am aware that pursuant to Section 837.06, Florida Statutes, whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree.

Signature: _____________________
Title: __________________________
Telephone Number: _____________
Fax Number: __________________

Sworn to and subscribed before me this ______________________ day of _____________________, 20__.

My Commission expires:

(SEAL)

____
Notary Public
State of Florida

NOTICE TO CUSTOMERS

Pursuant to Section 367.081(4)(b), Florida Statutes, water and wastewater utilities are permitted to pass through, without a public hearing, a change in rates resulting from: an increase or decrease in rates charged for utility services received from a governmental agency or another regulated utility and which services were redistributed by the utility to its customers; an increase or decrease in the rates that it is charged for electric power, the amount of ad valorem taxes assessed against its used and useful property, the fees charged by the Department of Environmental Protection in connection with the National Pollutant Discharge Elimination System Program, or the regulatory assessment fees imposed upon it by the Commission; and costs incurred for water quality or wastewater quality testing required by the Department of Environmental Protection.

On ______________________, ______________________________
(date) (name of company)

filed its notice of intention with the Florida Public Service Commission to increase water and wastewater rates in ______________ County pursuant to this Statute. The filing is subject to review by the Commission Staff for accuracy and completeness. Water rates will increase by approximately ______% and wastewater rates by ______%. These rates should be reflected on your bill for service rendered on or after ________________________.(date)

If you should have any questions, please contact your local utility office. Be sure to have your account number handy for quick reference.

COMMISSIONERS:
JULIE I. BROWN, CHAIRMAN
LISA POLAK EDGAR
ART GRAHAM
RONALD A. BRISÉ
JIMMY PATRONIS

STATE OF FLORIDA

DIVISION OF
ACCOUNTING AND FINANCE
ANDREW L. MAUREY
DIRECTOR
(850) 413-6900

Public Service Commission

Month Day, 2016

All Florida Public Service Commission
Regulated Water & Wastewater Utilities

Re: Docket No. 150005-WS - 2016 Price Index

Dear Utility Owner:

Since March 31, 1981, pursuant to the guidelines established by Section 367.081(4)(a), Florida Statutes (F.S.), and Rule 25-30.420, Florida Administrative Code (F.A.C.), the Commission has established a price index increase or decrease for major categories of operating costs. The intent of this rule is to insure that inflationary pressures are not detrimental to utility owners, and that any possible deflationary pressures are not adverse to rate payers. By keeping up with index and pass-through adjustments, utility operations can be maintained at a level sufficient to insure quality of service for the rate payers.

Pursuant to Rule 25-30.420(1)(a), F.A.C., all operation and maintenance expenses shall be indexed with the exception of:

a) Pass-through items pursuant to Section 367.081(4)(b), F.S.;

b) Any amortization of rate case expense; and

c) Disallowances or adjustments made in an applicant's most recent rate proceeding.

Upon the filing of a request for an index and/or pass-through increase, staff will review the application and modify existing rates accordingly. If for no other reason than to keep up with escalating costs, utilities throughout Florida should file for this rate relief on an annual basis. Utilities may apply for a 2016 Price Index anytime between April 1, 2016, through March 31, 2017. The attached package will answer questions regarding what the index and pass-through rate adjustments are, how to apply for an adjustment, and what needs to be filed in order to meet the filing requirements. While this increase for any given year may be minor, (see chart below), the long-run effect of keeping current with rising costs can be substantial.

Year	Annual Commission Approved Index	Year	Annual Commission Approved Index
1991	4.12%	2004	1.60%
1992	3.63%	2005	2.17%
1993	3.33%	2006	2.74%
1994	2.56%	2007	3.09%
1995	1.95%	2008	2.39%
1996	2.49%	2009	2.55%
1997	2.13%	2010	0.56%
1998	2.10%	2011	1.18%
1999	1.21%	2012	2.41%
2000	1.36%	2013	1.63%
2001	2.50%	2014	1.41%
2002	2.33%	2015	1.57%
2003	1.31%	2016	1.29%

Please be aware that pursuant to Section 837.06, F.S., whoever knowingly makes a false statement in writing with the intent to mislead a public servant in the performance of his official duty shall be guilty of a misdemeanor of the second degree.

Our staff is available at (850) 413-6900 should you need assistance with your filing. If you have any questions, please do not hesitate to call.

Sincerely,

Andrew L. Maurey
Director

Enclosures

Item 8

FILED NOV 18, 2015
DOCUMENT NO. 07297-15
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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (Smith, Mouring)
Office of the General Counsel (Brownless)

RE: Docket No. 150137-SU – Petition for approval to defer legal expenses associated with the resolution of land use issues for utility treatment facilities that are located in Polk County by West Lakeland Wastewater, Inc..

AGENDA: 12/03/15 – Regular Agenda – Proposed Agency Action - Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

West Lakeland Wastewater, Inc. (West Lakeland or utility) is a Class C wastewater utility that serves approximately 302 customers in Polk County. Water service is provided by the City of Lakeland. According to West Lakeland's 2014 annual report, total gross revenues were $116,063 and total operating expenses were $120,000, resulting in a net loss of $3,937.

By letter dated March 26, 2009, West Lakeland gave notice of abandonment effective June 30, 2009. On May 13, 2009, the Polk County Attorney filed a Petition for Appointment of Receiver for West Lakeland in the Circuit Court of the Tenth Judicial Circuit (Circuit Court). The Circuit Court appointed Mr. Mike Smallridge as receiver for the wastewater system. On September 8, 2009, the Commission acknowledged West Lakeland's abandonment and the Court's appointment of Mr. Smallridge as receiver.[1]

On March 3, 2013, Mr. Smallridge sent a letter to the Commission requesting that a docket be opened to transfer Certificate No. 515-S from West Lakeland, Inc. to West Lakeland Wastewater, LLC. This application was withdrawn by the utility in a letter dated September 11, 2014.

On April 23, 2015, West Lakeland filed a petition for approval to defer expenses associated with a lawsuit to obtain an easement to its ponds and spray fields, and to amortize these expenses over three years. The total legal costs to date associated with this litigation are $6,245.

[1] Order No. PSC-09-0607-FOF-SU as amended by PSC-09-0607A-FOF-SU, issued February 16, 2010, in Docket No. 090154-SU, *In re: Notice of abandonment of wastewater system for The Village of Lakeland Mobile Home Park in Polk County, by West Lakeland Wastewater, Inc.*

Discussion of Issues

Issue 1: Should the Commission approve West Lakeland Wastewater, Inc.'s petition to defer expenses related to obtaining an easement to its clearing ponds and spray fields?

Recommendation: Yes. The Commission should approve the petition by West Lakeland to defer the legal expenses associated with obtaining an easement to its ponds and spray field. (Smith)

Staff Analysis: On April 23, 2015, West Lakeland filed a letter seeking approval to defer expenses associated with a lawsuit to obtain an easement to its ponds and spray fields, and to amortize these expenses over three years. The utility has stated the total legal costs to date associated with this litigation are $6,245.

The 2013 transfer application was withdrawn because the utility did not own or have a long-term lease for the land on which the ponds and spray fields are located. Rule 25-30.037(2)(Q), F.A.C., requires "evidence that the utility owns the land upon which the utility treatment facilities are located, or a copy of an agreement which provides for the continued use of the land, such as a 99-year lease. The Commission may consider a written easement or other cost-effective alternative."

The concept of deferral accounting allows companies to defer costs due to events beyond their control and seek recovery through rates at a later time. The alternative would be for the company to seek a rate case each time it experiences an exogenous event. To ensure that the utility is given the opportunity to recover the reasonable costs associated with the process of obtaining an easement, staff recommends that the Commission approve the utility's petition to defer expenses related to obtaining an easement to its ponds and spray fields.

The expenses in the instant docket relate to legal fees incurred by the utility in trying to obtain an easement to property which contain the ponds and spray field. Since this situation is still ongoing, creating a regulatory asset is not possible at this time. Upon completion of a fully executed easement, Mr. Smallridge would be able to file for the establishment and recovery of the deferred legal fees through a regulatory asset. Therefore, staff recommends the Commission approve the petition by West Lakeland to defer the legal expenses associated with obtaining an easement to its ponds and spray field.

Issue 2: Should West Lakeland file a transfer application within 90 days of a fully executed easement?

Recommendation: Yes. (Smith)

Staff Analysis: In Docket Nos. 140174-WU and 140176-WU, the Commission imposed conditions on any new purchases of Commission-regulated utilities by Mr. Smallridge.[2] Condition number 5 states, "If Michael Smallridge purchases, either directly or indirectly, any other Commission-regulated utilities prior to December 31, 2017, an application for transfer shall be submitted within 90 days of such purchase." Despite the fact that Mr. Smallridge was already appointed receiver of West Lakeland when the Commission rendered its decision, staff believes the underlying reasons for this condition apply in this case. Therefore, staff is recommending Mr. Smallridge be required to file for a transfer within 90 days of a fully executed easement.

[2] Order No. PSC-15-0420-PAA-WU, issued October 5, 2015, in Docket No. 140174-WU, *Notice of Proposed Agency Action Order approving transfer of Certificate No. 117-W and setting new book value for transfer purposes;* and Order No. PSC-15-0422-PAA-WU, issued October 6, 2015, in Docket No. 140176-WU, *Notice of Proposed Agency Action Order approving transfer of Certificate No. 116-W and setting new book value for transfer purposes.*

Issue 3: Should this docket be closed?

Recommendation: If a person whose substantial interests are affected by the proposed agency action does not file a protest within 21 days of the issuance of the order, a consummating order should be issued and this docket should be closed. (Brownless, Smith)

Staff Analysis: If a person whose substantial interests are affected by the proposed agency action does not file a protest within 21 days of the issuance of the order, a consummating order should be issued and this docket should be closed.

Item 9

FILED NOV 18, 2015
DOCUMENT NO. 07309-15
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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (Hill, King)
Division of Accounting and Finance (Fletcher, Frank, Norris)
Division of Economics (Bruce)
Office of the General Counsel (Mapp, Brownless)

RE: Docket No. 150091-WS – Application for approval of transfer of Certificate Nos. 490-W and 425-S from East Marion Sanitary Systems, Inc. to East Marion Utilities, LLC, in Marion County.

AGENDA: 12/03/15 – Regular Agenda – Proposed Agency Action for Issue 2 – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Patronis

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On March 20, 2015, East Marion Sanitary Systems, Inc. (Utility or seller) filed an application for the transfer of Certificate Nos. 490-W and 425-S to East Marion Utilities, LLC (buyer) in Marion County. The service area is located in the St. Johns River Water Management District and is in a water resource caution area. According to the Utility's 2014 Annual Report, the Utility serves 103 water customers and 92 wastewater customers with operating revenue of $59,272, which designates it as a Class C utility.

Certificate Nos. 490-W and 425-S were originally granted in 1987.[1] In 1990 and 1997, there were transfers of majority organizational control.[2] The rates and charges for utility service were last approved in a staff-assisted rate case in 2002.[3]

This recommendation addresses the transfer of the water and wastewater systems and the net book value of the water and wastewater systems at the time of transfer. The Commission has jurisdiction pursuant to Section 367.071, Florida Statutes (F.S.).

[1] Order No. 17837, issued July 7, 1987, in Docket No. 870389-WU, *In re: Application of East Marion Water Distribution, Inc. for a certificate to operate a water utility in Marion County, Florida.*

[2] Order No. 24553, issued May 20, 1991, in Docket No. 900603-WS, *In Re: Application for transfer of majority organizational control of East Marion Water Distribution, Inc. and East Marion Sanitary Systems, Inc. in Marion County from Penelope A. Wagner, trustee for the Estate of Eric E. Wagner, to Forest Lake Village – Del American Ltd.* and Order No. PSC-98-0928-FOF-WS, issued July 7, 1998, in Docket No. 971269-WS, *In Re: Application for transfer of majority organizational control of East Marion Sanitary Systems, Inc. and East Marion Water Distribution, Inc. in Marion County from Del-American/First Federal of Osceola to Herbert Hein, and change in name on Certificate No. 490-W from East Marion Water Distribution, Inc. to East Marion Sanitary Systems, Inc.*

[3] Order No. PSC-02-1168-PAA-WS, issued August 26, 2002, in Docket No. 010869-WS, *In re: Application for staff-assisted rate case in Marion County by East Marion Sanitary Systems, Inc.*

Discussion of Issues

Issue 1: Should the transfer of East Marion Sanitary Systems, Inc.'s water and wastewater systems and Certificate Nos. 490-W and 425-S to East Marion Utilities, LLC be approved?

Recommendation: Yes. The transfer of the water and wastewater systems and Certificate Nos. 490-W and 425-S is in the public interest and should be approved effective the date of the Commission vote. The resultant order should serve as the buyer's certificate and should be retained by the buyer. The existing rates and charges should remain in effect until a change is authorized by the Commission in a subsequent proceeding. The tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), Florida Administrative Code (F.A.C.). The seller should be responsible for all Regulatory Assessment Fees (RAFs) payable through the date of closing. The buyer should be responsible for filing the 2015 Annual Report and all future annual reports, and RAFs subsequent to the date of closing. (Hill, Frank)

Staff Analysis:

On March 20, 2015, East Marion Sanitary Systems, Inc. filed an application for approval to transfer Certificate Nos. 490-W and 425-S to East Marion Utilities, LLC in Marion County pursuant to Rule 25-30.037, F.A.C. Included within the application was a copy of a sales contract dated January 9, 2015 between East Marion Sanitary Systems, Inc. and Florida Utility Services 1, LLC. However, in the August 4, 2015 response to Staff's request for additional information, a corrected bill of sale was provided, also dated January 9, 2015, between East Marion Sanitary Systems, Inc. and East Marion Utilities, LLC. East Marion Utilities, LLC was registered with the Florida Department of State, Division of Corporations on January 12, 2015. East Marion Utilities, LLC is currently providing water and wastewater services to East Marion Sanitary Services, Inc.'s customers; however, the certificated entity remains unchanged until the Commission approves the transfer of the certificate.

The application is in compliance with Section 367.071, F.S., and Commission rules concerning applications for transfer of certificates. The sale occurred on January 9, 2015, contingent upon Commission approval, pursuant to Section 367.071(1), F.S.

Noticing, Territory, and Land Ownership

The application contains proof of compliance with the noticing provisions set forth in Section 367.071, F.S., and Rule 25-30.030, F.A.C. No objections to the transfer were filed, and the time for doing so has expired. The application contains a description of the Utility's water and wastewater service territory, which is appended to this recommendation as Attachment A. The application contains a copy of a ninety-nine year lease that was executed on February 3, 2003 and assigned to the buyer on September 14, 2015. The lease serves as evidence that the buyer has the right to continuously occupy and use the land upon which the water treatment facilities are located pursuant to Rule 25-30.037(2)(q), F.A.C.

Purchase Agreement and Financing

Pursuant to Rule 25-30.037(2)(g), (h), and (i), F.A.C., the application contains a statement regarding financing and a copy of the Purchase Agreement, which includes the purchase price, terms of payment, and a list of the assets purchased. There are no customer deposits, guaranteed revenue contracts, developer agreements, customer advances, leases, or debt of the Utility that must be disposed of with regard to the transfer. According to the purchase agreement, the total purchase price for the water and wastewater assets is $107,000 with $10,000 paid at closing, and the remainder paid through a 10 year note at 6 percent. According to the buyer's registered agent, Michael Smallridge, the sale closed on January 1, 2015, subject to Commission approval, pursuant to Section 367.071(1), F.S.

Facility Description and Compliance

The water treatment system consists of a single well with a ground storage tank with a capacity of 6,000 gallons, and a liquid chlorination system used for disinfection. Wastewater treatment is performed by an activated sludge domestic wastewater treatment plant. Treatment consists of flow equalization, aeration, secondary clarification, chlorination, and aerobic digestion of biosolids with a 0.050 million gallons per day three month average daily flow permitted capacity. Effluent is disposed of via three rapid infiltration basins. Staff contacted the Florida Department of Environmental Protection (DEP) concerning the compliance status relative to any Notices of Violation or any DEP consent orders. DEP stated that the system is not subject to any outstanding violations or consent orders.

Technical and Financial Ability

Pursuant to Rule 25-30.037(1)(j), F.A.C., the application contains statements describing the technical and financial ability of the applicant to provide service to the proposed service area. As referenced in the transfer application, the buyer will fulfill the commitments, obligations and representation of the seller with regards to utility matters. Also, as referenced in the transfer application and specified in previous dockets,[4] Mr. Smallridge was appointed to the Citrus County Water and Wastewater Authority, the local regulatory body for Citrus County, where he served for seven years. Mr. Smallridge also served as the "Class C" representative for the Governors Study Committee for Investor Owned Water and Wastewater Utility Systems in 2013. Mr. Smallridge maintains a regular yearly schedule of training classes through the Florida Rural Water Association and completed the NARUC Utility Rate School in 2001. Mr. Smallridge serves as the appointed circuit court receiver for Four Points Utility Corporation, Bimini Bay Utilities, and West Lakeland Wastewater, Inc. Mr. Smallridge also owns Pinecrest Utilities, LLC, Crestridge Utilities, LLC, and Holiday Gardens Utilities, LLC. In addition, Florida Utility Services 1, LLC, which is owned and operated by Mr. Smallridge, purchased Charlie Creek Utilities, LLC.[5] In total, Mr. Smallridge owns, is the receiver of, or is the manager of a total of eight Class C water and wastewater facilities, seven of which are regulated by the Commission.

Staff reviewed Mr. Smallridge's personal financial statements and tax returns, as well as the financial statements and tax returns of Florida Utility Services 1, LLC. Mr. Smallridge also provided staff with a three-year capital expenditure and funding estimate[6] which included the

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[4] Docket No. 140174-WU, *In re: Application for approval of transfer of Certificate No. 117-W from Crestridge Utilities Corporation to Crestridge Utilities, LLC, in Pasco County;* Docket No. 140176-WU, *In re: Application for approval of transfer of Certificate No. 116-W from Holiday Gardens Utilities, Inc. to Holiday Gardens Utilities, LLC, in Pasco County.*

[5] An application for original certificate was submitted with the Commission on August 21, 2015.

[6] Document No. 04029-15, filed June 30, 2015.

status of recent improvements and indicates access to additional sources of capital as well. It should also be noted that the buyer has accepted responsibility over the Commission-ordered refunds that were required of the previous owner.[7] Based on the above, the buyer has demonstrated the technical and financial ability to provide service to the existing service territory.

Based on the above, staff believes the buyer has demonstrated the technical and financial ability to provide service to the existing service territory.

Rates and Charges

The Utility's rates and charges were last approved in a 2002 staff-assisted rate case.[8] The Utility's miscellaneous service charges were amended in 2009.[9] Since the Utility's last rate case, the rates have been changed by four price index rate increases and a rate decrease to remove an expired rate case expense amortization. The Utility's existing rates and charges are shown on Schedule No. 1 for water and Schedule No. 2 for wastewater. Rule 25-9.044(1), F.A.C., provides that, in the case of a change of ownership or control of a utility, the rates, classifications, and regulations of the former owner must continue unless authorized to change by this Commission. Therefore, staff recommends that the Utility's existing rates and charges remain in effect until a change is authorized by this Commission in a subsequent proceeding.

Regulatory Assessment Fees and Annual Reports

Staff has verified that the Utility is current on the filing of annual reports and RAFs through December 31, 2014. The seller will be responsible for all RAFs payable through the date of closing. The buyer is responsible for filing the 2015 Annual Report and all future annual reports, and RAFs subsequent to the date of closing.

Conclusion

Based on the foregoing, staff recommends that the transfer of the water and wastewater systems and Certificate Nos. 490-W and 425-S is in the public interest and should be approved effective the date of the Commission vote. The resultant order should serve as the buyer's certificate and should be retained by the buyer. The existing rates and charges should remain in effect until a change is authorized by the Commission in a subsequent proceeding. The tariff pages reflecting the transfer should be effective on or after the stamped approval date on the tariff sheets pursuant to Rule 25-30.475(1), F.A.C. The seller should be responsible for all RAFs payable through the date of closing. The buyer should be responsible for filing the 2015 Annual Report and all future annual reports, and RAFs subsequent to the date of closing.

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[7] Docket No. 080064-WU, *In re: Complaint against East Marion Sanitary Systems, Inc. by Mabelle Gregorio, Angela and Dennis Fountain, and Terry Will.*

[8] Order PSC-02-1168-PAA-WS, issued August 26, 2002, in Docket No. 010869-WS, *In re: Application for staff assisted rate case in Marion County by East Marion Sanitary Systems, Inc.*

[9] Order PSC-09-0263-TRF-WU, issued April 27, 2009, in Docket No. 080562-WU, *In re: Request for approval of amendment to connection/transfer sheets, increase in returned check charge, amendment to miscellaneous service charges, increase in meter installation charges, and imposition of new tap-in fee, in Marion County, by East Marion Sanitary Systems Inc.*

Issue 2: What is the appropriate net book value for the East Marion Sanitary Systems, Inc.'s water and wastewater systems for transfer purposes and should an acquisition adjustment be approved?

Recommendation: The net book value of the water and wastewater systems for transfer purposes is $24,676 and $60,414, respectively, as of December 31, 2014. An acquisition adjustment should not be included in rate base. Within 90 days of the date of the final order, East Marion Utilities, LLC should be required to notify the Commission in writing, that it has adjusted its books in accordance with the Commission's decision. The adjustments should be reflected in East Marion Utilities, LLC's 2015 Annual Report when filed. (Frank)

Staff Analysis: Rate base was last established for the Utility as of December 31, 2000.[10] The purpose of establishing net book value (NBV) for transfers is to determine whether an acquisition adjustment should be approved. The NBV does not include normal ratemaking adjustments for used and useful plant or working capital. The Utility's NBV has been updated to reflect balances as of December 31, 2014. Staff's recommended NBV, as described below, is shown on Schedule Nos. 1 and.2.

Utility Plant in Service (UPIS)

The Utility's general ledger reflected water and wastewater UPIS balances of $111,551 and $207,010, respectively, as of December 31, 2014. Staff reviewed UPIS additions since the last rate case proceeding and as a result has increased UPIS for water by $30,786 and wastewater by $275,092. Therefore, staff recommends that the Utility's water and wastewater UPIS balances as of December 31, 2014, should be $142,336 and $482,102, respectively.

Land

The Utility's general ledger reflected a land balance of $35,000 for water and $50,000 for wastewater, as of December 31, 2014. In Order No. PSC-02-1168-PAA-WS, issued August 6, 2002, the Commission established the value of the land to be $0 for water and $0 for wastewater because the Utility leased the land where the water and wastewater plants are located. The Utility continues to lease the land. There have been no additions to land purchased since that order was issued. As a result, land for water should be reduced by $35,000 and land for wastewater should be reduced by $50,000. Therefore, staff recommends land of $0 for water and $0 for wastewater, as of December 31, 2014.

Accumulated Depreciation

The Utility's general ledger reflected water and wastewater accumulated depreciation balances of $80,268 and $156,894, respectively, as of December 31, 2014. Staff calculated that the appropriate accumulated depreciation balance to be $94,497 for water and $370,310 for wastewater. As a result, accumulated depreciation should be increased by $14,229 for water and $213,416 for wastewater to reflect an accumulated depreciation balance of $94,497 for water and $370,310 for wastewater, as of December 31, 2014.

[10] Order No. PSC-02-1168-PAA-WS, issued August 6, 2002, in Docket No. 010869-WS, *In re: Application for a staff-assisted rate case by East Marion Sanitary Systems in Marion County.*

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

As of December 31, 2014, the Utility's general ledger reflected water and wastewater CIAC balances of $39,135 and $76,315, respectively; and accumulated amortization of CIAC balances of $25,317 and $26,664, respectively. Staff increased water and wastewater CIAC by $565 and $1,285, respectively, to reflect prior Commission-ordered adjustments. Also, staff decreased water and wastewater accumulated amortization of CIAC by $8,780 and $442, respectively, to reflect the appropriate Commission-ordered adjustments. Therefore, staff recommends a CIAC balance of $39,700 for water and $77,600 for wastewater and accumulated amortization of CIAC balance of $16,537 for water and $26,222 for wastewater, as of December 31, 2014.

Net Book Value

The Utility's general ledger reflected NBV of $52,465 for water and $50,465 for wastewater. Based on the adjustments described above, staff recommends that the NBV for the Utility's water and wastewater systems as of December 31, 2014, are $24,676 and $60,414, respectively, for a total NBV of $85,090. Staff's recommended NBV and the National Association of Regulatory Utility Commissioners, Uniform System of Accounts (NARUC USOA) balances for UPIS and accumulated depreciation are shown on Schedule Nos. 3 and 4, as of December 31, 2014.

Acquisition Adjustment

An acquisition adjustment results when the purchase price differs from the NBV of the assets at the time of the acquisition. The Utility and its assets were purchased for $107,000. As stated above, staff has determined the appropriate NBV total to be $85,090. Pursuant to Rule 25-30.0371, F.A.C., a positive acquisition adjustment may be appropriate when the purchase price is greater than the NBV, and a negative acquisition adjustment may be appropriate when the purchase price is less than NBV. However, pursuant to Rule 25-30.0371(2), F.A.C., a positive acquisition adjustment shall not be included in rate base unless there is proof of extraordinary circumstances. The buyer did not request a positive acquisition adjustment. As such, staff recommends that no positive acquisition adjustment be approved.

Conclusion

Based on the above, staff recommends that the NBV of East Marion Sanitary Systems, Inc.'s water and wastewater systems for transfer purposes is $24,676 and $60,414, respectively, as of December 31, 2014. No acquisition adjustment should be included in rate base. Within 90 days of the date of the final order, the buyer should be required to notify the Commission, in writing, that it has adjusted its books in accordance with the Commission's decision. The adjustments should be reflected in East Marion Utility LLC's 2015 annual report when filed.

Issue 3: Should this docket be closed?

Recommendation: If no protest to the proposed agency action issues is filed by a substantially affected person within 21 days of the date of the order, a consummating order should be issued and the docket should be closed administratively after East Marion Utilities, LLC has provided proof that its general ledgers have been updated to reflect the Commission-approved balances as of January 1, 2015. (Mapp)

Staff Analysis: If no protest to the proposed agency action issues is filed by a substantially affected person within 21 days of the date of the order, a consummating order should be issued and the docket should be closed administratively after East Marion Utilities, LLC has provided proof that its general ledgers have been updated to reflect the Commission-approved balances as of January 1, 2015.

FLORIDA PUBLIC SERVICE COMMISSION

Authorizes
East Marion Utilities, LLC
pursuant to
Certificate Number 490-W

to provide water service in Marion 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
17837	07/14/87	870389-WU	Original Certificate
24553	05/20/91	900603-WS	Transfer of Majority Organizational Control
PSC-98-0928-FOF-WS	07/07/98	971269-WS	Transfer of Majority Organizational Control
*	*	150091-WS	Transfer of Certificate

***Order Numbers and dates to be provided at time of issuance**

East Marion Utilities, LLC
Marion County
Description of Water Territory

PER ORDER NO. PSC-98-0928-FOF-WS:

The following described lands located in portions of Section 7, 8, and 17, Township 15 South, Range 24 East, Marion County, Florida:

Beginning at the Southwest corner of the Southwest 1/4 of the Northwest 1/4 of Section 8, Township 15 South, Range 24 East, Marion County, Florida, thence North 00°29'46" West along the West boundary of said Section 8 a distance of 839.97 feet to the Southwesterly right-of-way line of State Road No. 40, thence South 56°59'12" East along said Southwesterly right-of-way line 531.25 feet, thence South 33°01'47" West 89.79 feet, thence South 00°11'26" East 1385.87 feet, thence South 36°25'52" East 285.41 feet to the approximate shoreline of Lake Walenda, thence run into said Lake South 29°57'59" East 201.43 feet to a point on the aforesaid approximate shoreline of Lake Walenda, thence run into said Lake South 29°57'59" East 201.43 feet to a point in said Lake, said point being the Southeast corner of the West 1/2 of the Northwest 1/4 of the Southwest 1/4 of said Section 8, thence South 89°30'58" West along said South boundary 329.84 feet to a point on the aforesaid approximate shoreline of Lake Walenda, thence continue South 89°30'58" West along said South boundary 330.29 feet to the Southwest corner of said West 1/2 of the Northwest 1/4 of the Southwest 1/4, thence North 00°10'04" along the West boundary of said Section 8 a distance 1319.86 feet to the POINT OF BEGINNING.

Also: Lots 107, 108, and 109, in the Town of Walenda, situated in the Southwest 1/4 of Section 8, Township 15 South, Range 24 East, as per plat thereof recorded in Plat Book "E", page 23, Public Records of Marion County, Florida. Less and excepting therefrom that part of the East 200 feet of West 1181.38 feet of the Southwest 1/4 of said Section 8, Township 15 South, Range 24 East, lying South of Lake Walenda, all of which lies in Lot 109.

Also: South 1/2 of Southeast 1/4 of Section 7, Township 15 South, Range 24 East, except the west 70 acres, thereof.

Also: That part of the West 3/4 of the Northwest 1/4 of Section 17, Township 15 South, Range 24 East, lying North of Fort Gates Road, except additional road right-of-way conveyed in Official Records Book 991, page 173.

FLORIDA PUBLIC SERVICE COMMISSION

Authorizes
East Marion Utilities, LLC
pursuant to
Certificate Number 425-S

to provide wastewater service in Marion 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
17837	07/14/87	870389-WU	Original Certificate
24553	05/20/91	900603-WS	Transfer of Majority Organizational Control
PSC-98-0928-FOF-WS	07/07/98	971269-WS	Transfer of Majority Organizational Control
*	*	150091-WS	Transfer of Certificate

***Order Numbers and dates to be provided at time of issuance**

East Marion Utilities, LLC
Marion County
Description of Wastewater Territory

PER ORDER NO. PSC-98-0928-FOF-WS:

The following described lands located in portions of Section 7, 8, and 17, Township 15 South, Range 24 East, Marion County, Florida:

Beginning at the Southwest corner of the Southwest 1/4 of the Northwest 1/4 of Section 8, Township 15 South, Range 24 East, Marion County, Florida, thence North 00°29'46" West along the West boundary of said Section 8 a distance of 839.97 feet to the Southwesterly right-of-way line of State Road No. 40, thence South 56°59'12" East along said Southwesterly right-of-way line 531.25 feet, thence South 33°01'47" West 89.79 feet, thence South 00°11'26" East 1385.87 feet, thence South 36°25'52" East 285.41 feet to the approximate shoreline of Lake Walenda, thence run into said Lake South 29°57'59" East 201.43 feet to a point on the aforesaid approximate shoreline of Lake Walenda, thence run into said Lake South 29°57'59" East 201.43 feet to a point in said Lake, said point being the Southeast corner of the West 1/2 of the Northwest 1/4 of the Southwest 1/4 of said Section 8, thence South 89°30'58" West along said South boundary 329.84 feet to a point on the aforesaid approximate shoreline of Lake Walenda, thence continue South 89°30'58" West along said South boundary 330.29 feet to the Southwest corner of said West 1/2 of the Northwest 1/4 of the Southwest 1/4, thence North 00°10'04" along the West boundary of said Section 8 a distance 1319.86 feet to the POINT OF BEGINNING.

Also: Lots 107, 108, and 109, in the Town of Walenda, situated in the Southwest 1/4 of Section 8, Township 15 South, Range 24 East, as per plat thereof recorded in Plat Book "E", page 23, Public Records of Marion County, Florida. Less and excepting therefrom that part of the East 200 feet of West 1181.38 feet of the Southwest 1/4 of said Section 8, Township 15 South, Range 24 East, lying South of Lake Walenda, all of which lies in Lot 109.

Also: South 1/2 of Southeast 1/4 of Section 7, Township 15 South, Range 24 East, except the west 70 acres, thereof.

Also: That part of the West 3/4 of the Northwest 1/4 of Section 17, Township 15 South, Range 24 East, lying North of Fort Gates Road, except additional road right-of-way conveyed in Official Records Book 991, page 173.

East Marion Utilities, LLC
Monthly Water Rates

Residential and General Service	
Base Facility Charge by Meter Size	
5/8" x 3/4"	$10.05
3/4"	$15.10
1"	$25.15
1 1/2"	$50.29
2"	$80.47
3"	$160.94
4"	$251.47
6"	$502.93
Charge Per 1,000 gallons - Residential	
0-10,000 gallons	$2.11
Over 10,000 gallons	$3.15
Charge Per 1,000 gallons – General Service	$2.46

Initial Customer Deposits

Residential Service and General Service	
5/8" x 3/4"	$61.00
All over 5/8" x 3/4"	2x Average Estimated Bill

Miscellaneous Service Charges

	Business Hours		After Hours
Initial Connection Charge	$45.00		$75.00
Normal Reconnection Charge	$45.00		$75.00
Disconnection Charge	$45.00		$75.00
Violation Reconnection Charge	$50.00		$80.00
Premises Visit Charge	$55.00		$85.00
Late Payment Charge		$5.00	
NSF Check Charge		Actual Cost	

Service Availability Charges

Main Extension Charge	
Residential – Per ERC	$255.00
All Other per gallon	$0.73
Meter Installation	
5/8" x 3/4"	$195.00
Plant Capacity Charge	
Residential – Per ERC	$112.00
All Other per gallon	$0.32
Irrigation Service Line Installation Charge	
5/8" x 3/4" (less than 20 feet)	$1,400.00
5/8" x 3/4" (20 feet to 40 feet)	$1,800.00
5/8" x 3/4" (Over 40 feet or cul-de-sac)	$2,600.00

East Marion Utilities, LLC
Monthly Wastewater Rates

Residential Service	
Base Facility Charge – All Meter Sizes	$15.37
Charge Per 1,000 gallons	$4.69
10,000 gallon cap	
General Service	
Base Facility Charge by Meter Size	
5/8" x 3/4"	$15.37
3/4"	$23.05
1"	$38.42
1 1/2"	$76.84
2"	$122.92
3"	$245.86
4"	$384.16
6"	$768.28
Charge Per 1,000 gallons	$5.63

Initial Customer Deposits

Residential Service and General Service	
5/8" x 3/4"	$80.00
All over 5/8" x 3/4"	2x Average Estimated Bill

Miscellaneous Service Charges

	Business Hours	After Hours
Initial Connection Charge	$45.00	$75.00
Normal Reconnection Charge	$45.00	$75.00
Disconnection Charge	$45.00	$75.00
Violation Reconnection Charge	Actual Cost	Actual Cost
Premises Visit Charge	$55.00	$85.00
Late Payment Charge	$5.00	
NSF Check Charge	Actual Cost	

Service Availability Charges

Main Extension Charge	
Residential – Per ERC	$517.00
All Other per gallon	$1.48
Plant Capacity Charge	
Residential – Per ERC	$358.00
All Other per gallon	$1.03

East Marion Utilities, LLC Water System Schedule

Water System

Schedule of Net Book Value as of December 31, 2014

Description	Balance Per Utility	Adjustments	Staff Recommended
Utility Plant in Service	$111,551	$30,786	$142,336
Land & Land Rights	35,000	(35,000)	0
Accumulated Depreciation	(80,268)	(14,229)	(94,497)
CIAC	(39,135)	(565)	(39,700)
Amortization of CIAC	25,317	(8,780)	16,537
Total	$52,465	($27,788)	$24,676

Explanation of Staff's Recommended
Adjustments to Net Book Value as of December 31, 2014
Water System

Explanation	**Amount**
A. Utility Plant In Service To reflect appropriate amount of utility plant in service.	$30,786
B. Land and Land Rights To reflect appropriate amount of land.	($35,000)
C. Accumulated Depreciation To reflect appropriate amount of accumulated depreciation.	($14,229)
D. Contributions-in-Aid-of-Construction (CIAC) To reflect appropriate amount of CIAC.	($565)
E. Accumulated Amortization of CIAC To reflect appropriate amount of accumulated amortization of CIAC.	($8,780)
Total Adjustments to Net Book Value as of December 31, 2014.	($27,788)

East Marion Utilities, LLC

Water System

Schedule of Staff Recommended Account Balances as of December 31, 2014

Account No.	Description	UPIS	Accumulated Depreciation
301	Organization	$944	($566)
304	Structures & Improvements	6,666	(5,422)
307	Wells & Springs	4,134	(2,912)
309	Supply Mains	3,760	(2,822)
311	Pumping Equipment	7,165	(3,210)
311	Pumping Equipment	3,226	(1,319)
320	Water Treatment Equipment	681	(681)
330	Distribution Reservoirs & Standpipes	27,475	(19,981)
331	Transmission & Distribution Mains	63,034	(39,801)
333	Services	19,071	(13,082)
334	Meters & Meter Installations	6,181	(4,700)
	Total	$142,336	($94,497)

East Marion Utilities, LLC Wastewater System Schedule

Wastewater System

Schedule of Net Book Value as of December 31, 2014

Description	**Balance Per Utility**	**Adjustments**	**Staff Recommended**
Utility Plant in Service	$207,010	$275,092	$482,102
Land	50,000	(50,000)	0
Accumulated Depreciation	(156,894)	(213,416)	(370,310)
CIAC	(76,315)	(1,285)	(77,600)
Amortization of CIAC	26,664	(442)	26,222
Total	$50,465	$9,949	$60,414

**Explanation of Staff's Recommended
Adjustments to Net Book Value as of December 31, 2014
Wastewater System**

Explanation	**Amount**
A. Utility Plant In Service To reflect appropriate amount of utility plant in service.	$275,092
B. Land & Land Rights To reflect appropriate amount of Land.	($50,000)
C. Accumulated Depreciation To reflect appropriate amount of accumulated depreciation.	($213,416)
D. Contributions-in-Aid-of-Construction (CIAC) To reflect appropriate amount of CIAC.	($1,285)
E. Accumulated Amortization of CIAC To reflect appropriate amount of accumulated amortization of CIAC.	($442)
Total Adjustments to Net Book Value as of December 31, 2014.	$9,949

East Marion Utilities, LLC

Wastewater System

Schedule of Staff Recommended Account Balances as of December 31, 2014

Account No.	Description	UPIS	Accumulated Depreciation
351	Organization	$1,145	($687)
354	Structures & Improvements	17,419	(13,798)
360	Collection Sewers - Force	9,380	(8,335)
361	Collection Sewers - Gravity	194,373	(115,380)
362	Special Collection Structures	53,404	(34,626)
363	Services to Customers	25,901	(17,768)
380	Treatment & Disposal - Equipment	132,921	(132,913)
382	Outfall Sewer Lines	3,770	(3,014)
389	Other Plant	43,789	(43,789)
	Total	$482,102	($370,310)

Item 10

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Higgins, Wu)
Division of Accounting and Finance (Cicchetti)
Office of the General Counsel (Leathers)

RE: Docket No. 150162-EI – Petition for approval of 2015 depreciation study by Florida Public Utilities Company.

AGENDA: 12/03/15 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Patronis

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

Rule 25-6.0436(8)(a), Florida Administrative Code (F.A.C.), requires investor-owned electric utilities to file a comprehensive depreciation study at least once every four years. On July 1, 2015, Florida Public Utilities Company (FPUC or company) filed its 2015 Depreciation Study in accordance with this rule.[1] The company's last depreciation review was filed June 20, 2011, with an effective date of January 1, 2012.[2] Staff has completed its review of FPUC's 2015 Depreciation Study and presents its recommendations herein.

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[1] By letter dated June 22, 2015, FPUC requested a brief filing due date extension for submitting its 2015 depreciation study.

[2] Order No. PSC-12-0065-PAA-EI, issued February 13, 2012, in Docket No. 110207-EI, In re: 2011 depreciation study by Florida Public Utilities Company.

The Florida Public Service Commission (Commission) has jurisdiction pursuant to Sections 350.115 and 366.05, Florida Statutes (F.S.).

Issue 1: Should FPUC's current depreciation rates and amortization schedules be changed?

Recommendation: Yes. A review of the company's plant-associated planning and activities indicates a need for revising FPUC's currently prescribed depreciation rates. (Higgins)

Staff Analysis: FPUC's last comprehensive depreciation study was filed on June 20, 2011. By Order No. PSC-12-0065-PAA-EI,[3] the Commission approved revised depreciation components and rates, effective January 1, 2012. The company has filed its current study in accordance with Rule 25-6.0436(8)(a), F.A.C., which requires electric companies to file a comprehensive depreciation study at least once every four years from the submission date of the previously filed study. In staff's opinion, a review of the company's plant activity and related data indicates the need to further analyze, and where warranted, revise depreciation rates and amortization schedules. Staff's recommended changes are addressed in Issue 2.

[3] Order No. PSC-12-0065-PAA-EI, issued February 13, 2012, in Docket No. 110207-EI, In re: 2011 depreciation study by Florida Public Utilities Company.

Issue 2: What are the appropriate depreciation rates and amortization schedules for FPUC?

Recommendation: Staff's recommended average remaining lives, net salvages, reserve percentages, and resultant depreciation rates for FPUC are shown on Attachment A. The reserve percentages and depreciation rates are calculated using the reserve transfers recommended in Issue 3. The result of staff's proposals is a decrease in annual depreciation expense of approximately $229,415 in total, which is shown on Attachment B. Depreciation expenses are based on plant investment levels as of January 1, 2015. (Wu, Higgins)

Staff Analysis: This issue addresses the derivation of depreciation rates, and amortization schedules by plant account and by function, i.e. transmission, distribution, and general plant. Once formulated, depreciation rates are applied to account investment balances to derive annual expense amounts. Attachment A shows a comparison of FPUC's currently-approved depreciation rates along with staff's proposed rates for future use.[4] Attachment B is a comparison of the resulting expenses (current and proposed) based on investment levels as of January 1, 2015. Staff notes that the values listed on both Attachments A and B include recommended reserve transfers (revisions) and associated effects in accordance with its recommendation on Issue 3.

In its original 2015 depreciation study filing, FPUC provided the necessary elements for conducting a review of the company's plant and reserve activity. The filing included: annual investment and reserve data; life and retirement data; average age data; salvage data; as well as current and proposed depreciation components and rates. As a result of the study review, discovery and analytical processes, staff and FPUC agree on lives, net salvage amounts, and resulting depreciation rates for all accounts presented in this recommendation.[5] Below is an account-by-account discussion on the development of staff's proposals for Transmission Plant, Distribution Plant, and General Plant.

<u>Transmission Plant</u>

<u>Account 350.1 – Land Rights</u>

For this account, FPUC proposed to change the Average Service Life (ASL) from 65 years to 70 years. The company proposed no change in curve shape or Net Salvage (NS). Staff notes that more than 69 percent of the plant in this account is over 40 years old, with the remaining plant being over 50 years old. The company has no plans to retire any of this plant. Staff also notes that the proposed increase in ASL is moderate, and the resulting ASL is still in line with other investor-owned electric utilities (IOUs) in the state. Thus, staff recommends that an ASL of 70 years is appropriate. This results in an Average Remaining Life (ARL) of 26 years and a remaining life depreciation rate of 1.4 percent for Account 350.1.

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[4] Order No. PSC-12-0065-PAA-EI, issued February 13, 2012, in Docket No. 110207-EI, In re: 2011 depreciation study by Florida Public Utilities Company.
[5] Florida Public Utilities Company's Response to Staff's Report on FPUC's 2015 Depreciation Study, Schedule 2 (revised 10/20/2015).

Account 352 – Structures and Improvements

After reviewing the information provided by the company in this docket, staff recommends a remaining life depreciation rate of 1.8 percent for Account 352.

Account 353 – Station Equipment

FPUC proposed no change in the ASL of 40 years or the curve shape (S3). The average age of assets in this account is 13.4 years. Based on this combination of depreciation parameters, the ARL is 27 years (26.6 years before rounding) rather than 30 years as the company proposed. This account has experienced an average retirement rate of 1.72 percent and a growth rate of 44.8 percent over the study period. Staff recommends the S2 curve with a 40-year ASL as better matching the account's activity. This results in an ARL of 27 years. FPUC concurs with staff's recommendation.

The company proposed to retain a 10 percent NS level. Staff notes that FPUC is the only IOU in Florida that has a positive NS level for this account; and this account has experienced less than 2 percent retirement and an average of negative 21 percent NS during the current study period. Given the low frequency of retirement activity, staff believes reliance on the industry average is necessary.[6] Staff recommends reducing the NS level from 10 percent to 5 percent. This moderate change reflects the account's current activity and will bring FPUC closer to the industry average at the same time. FPUC concurs with staff's recommendation. The resulting remaining life depreciation rate is 2.6 percent for Account 353.

Account 354 – Towers & Fixtures

The company proposed no change in ASL, curve shape, or NS level for this account. There was no retirement or addition activity during the study period, which makes reliance on industry averages for guidance on life and salvage characteristics necessary. FPUC's proposed 55-year ASL and negative 15 percent NS level are in the range of reasonableness compared to other IOUs in the state. Staff recommends that a 55-year ASL and negative 15 percent NS be approved.

[6] Staff derived industry averages throughout this recommendation are based or relied upon NS or ASL information (underlying data of final rates) shown on the following Commission Orders:
Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, in Docket No. 090079-EI, In re: Petition for increase in rates by Progress Energy Florida, Inc.; Order No. PSC-11-0089-S-EI, issued February 1, 2011, in Docket Nos. 080677-EI and 090130-EI, In re: Petition for increase in rates by Florida Power & Light Company and 2009 depreciation and dismantlement study by Florida Power & Light Company (Order No. PSC-11-0089-S-EI settled all outstanding issues and appeals of Order No. 10-0153-FOF-EI, issued March 17, 2010, in Docket Nos. 080677-EI and 090130-EI, In re: Petition for increase in rates by Florida Power & Light Company and 2009 depreciation and dismantlement study by Florida Power & Light Company); Order No. PSC-12-0175-PAA-EI, issued April 3, 2012, in Docket No. 110131-EI, In re: Petition for approval of 2011 depreciation study and annual dismantlement accrual amounts by Tampa Electric Company; Order No. PSC-13-0670-S-EI, issued December 19, 2013, in Docket No. 130140-EI, In re: Petition for rate increase by Gulf Power Company (Order No. PSC-13-0670-S-EI continues depreciation rates prescribed by Order No. PSC-10-0458-PAA-EI, issued July 19, 2010, in Docket No. 090319-EI, In re: Depreciation and dismantlement study at December 31, 2009, by Gulf Power Company).

FPUC proposed to retain the currently prescribed curve shape of S5. Given the current average age of the assets in this account, staff recommends an S6 curve shape as better fitting and reflective of plant activity since the last study. This results in a 14.5-year ARL. FPUC concurs with staff's recommendation. The resulting remaining life depreciation rate is 2.1 percent for Account 354.

Account 355 – Poles and Fixtures

FPUC proposed to retain an ASL of 40 years and the R4 curve shape. This account has experienced an average retirement rate of 0.16 percent, and an average growth rate of 2.2 percent over the study period. Staff recommends that a 40-year ASL be approved because it is in line with other IOUs in the state. Staff also recommends an R5 curve shape as being more indicative of expected retirement dispersion given the asset's average age of 23.2 years. By using an R5 curve and an average asset age of 23.2 years, the resulting ARL is 16.9 years. FPUC concurs with staff's recommendation.

FPUC proposed a change in NS from negative 30 percent to negative 40 percent. This account has experienced an average NS of negative 261 percent over the study period. However, the company believes that this low level/percentage of retirement activity should not be taken as indicative of future retirement expectations for this account. Staff notes the proposed change represents a modest increase in expected removal costs upon asset retirement and will bring FPUC more in line with the average NS of other IOUs in the state. Staff recommends a NS level of negative 40 percent be approved. The resulting remaining life depreciation rate is 4.1 percent for Account 355.

Account 355.1 – Poles and Fixtures - Concrete

FPUC proposed to retain a 45-year ASL and the R4 curve, but to decrease the NS from negative 30 percent to negative 40 percent. After reviewing the account's average age and plant activity, staff recommends that FPUC's proposed 45-year ASL and R4 curve be approved. This results in a 41-year ARL.

With respect to NS, given there was no retirement activity recorded in this account during the study period, staff recommends the negative 30 percent NS be retained. The negative 30 percent NS is still reasonable compared to other IOUs in the state. FPUC concurs with staff's recommendation. The resulting remaining life depreciation rate is 2.9 percent for Account 355.1.

Account 356 – Overhead Conductors and Devices

This account experienced an approximate 21 percent growth rate during the current study period, with a retirement rate of 0.5 percent. The average age of assets in this account is 13.9 years. FPUC proposed a change in ASL from 45 years to 50 years, and to retain the current S2 curve shape. Staff notes that the company's proposed change in ASL is moderate, reflective of account activity, and is still within industry average for the state. Staff recommends a 50-year ASL be approved for this account. The resulting ARL is 36 years.

Account 356 has experienced a NS of negative 123 percent. FPUC proposes to reduce this account's NS from negative 10 percent to negative 20 percent (resulting in a greater capitalized amount to be recovered). Other IOUs in the state are estimating a NS ranging from negative 50 percent, to negative 20 percent, with FPUC's estimate being the highest. Staff recommends that a NS of negative 20 percent be approved. The negative 20 percent NS level reflects the account's recent activity and will bring FPUC more in line with other IOUs in the state. The resulting remaining life depreciation rate is 2.5 percent for Account 356.

Account 359 – Roads and Trails

After reviewing the information provided by the company in this docket, staff recommends a remaining life depreciation rate of 1.5 percent for Account 359.

Distribution Plant

Account 360.1 – Land Rights

FPUC proposed a moderate increase in ASL from 56 years to 60 years. The average age of this account's assets is 29.5 years. The account experienced no asset additions or retirements activity over the study period. The company indicated there have been no additions to this account since 2006, and there are no near-term plans for any retirements of existing investment. Staff recommends that a 60-year ASL be approved because it reflects this account's activity and is in line with other IOUs in the state. The resulting ARL is 31 years, and the remaining life depreciation rate is 1.6 percent for Account 360.1.

Account 361 – Structures and Improvements

FPUC proposed to increase the ASL from 55 years to 60 years, retain the SQ curve, and a NS level of negative 5 percent. This account experienced approximately 81 percent growth during the study period with no retirement activity. Currently, the company has no firm plans for any near-term retirements. As with other accounts having limited near-term retirement activity, reliance on industry expectations is necessary for life and salvage projections. Staff recommends that a 60-year ASL and NS level of negative 5 percent be approved. The recommended ASL will bring FPUC more in line with other IOUs in the state while the recommended NS level is closer to the industry average. The resulting ARL is 47 years, and the remaining life depreciation rate is 1.7 percent for Account 361.

Account 362 – Station Equipment

FPUC proposed to increase the ASL from 40 years to 45 years, retain the S3 curve, and a NS level of negative 10 percent. This account has experienced an approximate 21 percent growth rate during the study period, with the retirement rate being less than 0.3 percent. Other IOUs in the state are estimating ASLs ranging from 38 to 60 years, with FPUC being the lowest. Staff recommends that a 45-year ASL be approved. The change in ASL is moderate and it will bring FPUC more in line with the other IOUs in the state. The resulting ARL is 34 years, and the remaining life depreciation rate is 2.4 percent for Account 362.

Account 364 – Poles, Towers, and Fixtures

After reviewing the information provided by the company in this docket, staff recommends a remaining life depreciation rate of 3.9 percent for Account 364.

Account 365 – Overhead Conductors and Devices

FPUC proposed a moderate increase in ASL from 37 years to 40 years, changing the curve shape from R5 to R4, and retaining a NS level of negative 35 percent. This account experienced a growth rate of 21 percent during the study period, with the retirement rate being less than 0.4 percent. Staff recommends a 40-year ASL be approved because it is reflective of account activity and is also in the range of reasonableness when compared to other IOUs in the state. Staff also recommends retaining the R5 curve due to the combination of depreciation parameters (40-year ASL, average asset age of 19.3 years, and a retirement rate of 0.3 percent) being a better fit. The resulting ARL is 21 years (using the R5 curve). FPUC concurs with staff's recommendation.

With respect to NS, staff recommends that a NS level of negative 35 percent be approved primarily because it continues to be in the range of reasonableness compared to other electric IOUs in the state. The resulting remaining life depreciation rate is 3.4 percent for Account 365.

Account 366 – Underground Conduit

This account has experienced an approximate 0.1 percent retirement rate during the study period. FPUC proposed to retain the currently prescribed R5 curve shape with an ASL of 60 years. Staff recommends that a 60-year ASL and R5 curve be approved. These recommended parameters are within the state's industry range. Given the average asset age is 10.4 years, the resulting ARL is 50 years for this account.

Account 366 has experienced an approximate negative 60 percent average NS over the study period. The company proposes to change this account's NS rate from zero to negative 5 percent. Staff recommends a NS of negative 5 percent be approved because it is reflective of account activity and is still within the industry average range. The resulting remaining life depreciation rate is 1.8 percent for Account 366.

Account 367 – Underground Conductors and Devices

The retirement rate of this account over the study period is 0.4 percent. FPUC proposed to retain the current ASL of 35 years and the R3 curve shape. Staff recommends that a 35-year ASL be approved as it continues to be in the range of reasonableness compared to other IOUs in the state. Staff also recommends changing the curve shape to R4. Staff recommends changing the curve shape because a 35-year ASL with the R4 curve better matches account activity, which has an average asset age of 12.2 years. The resulting ARL is 23 years. FPUC concurs with staff's recommendation.

FPUC proposed to change this account's NS level from zero to negative 5 percent. Staff notes that this account has experienced nearly 50 percent removal costs during the study period. Staff recommends that FPUC's proposal, which is moderate, reflective of activities in the account, and within the range of industry averages, be approved. The resulting remaining life depreciation rate is 3.2 percent for Account 367.

Account 368 – Line Transformers

FPUC proposed to slightly increase the ASL from 29 to 30 years. This account has experienced an approximate 0.5 percent retirement rate with an approximate 9 percent growth rate. Staff believes this proposal reflects the account's activity and is in the range of reasonableness compared to other IOUs in the state. Staff recommends the 30-year ASL be approved. In FPUC's 2011 Depreciation Study review, staff proposed the continued use of the S6 curve. In FPUC's 2015 Depreciation Study, the company proposes to change the curve shape from S6 to S4. Given the current average asset age, ASL, and the retirement activity, staff recommends that a 30-year ASL with an S4 curve be approved because it better matches the account's activity. The resulting ARL is 12.4 years.

FPUC proposed to retain a NS level of negative 20 percent. FPUC recognizes that the average negative NS this account has experienced over the study period is much higher than 20 percent, but believes it is not indicative of future NS expectations. Given that this account has experienced limited retirement activity over the study period, staff believes statistical analyses is not solely reliable for determining salvage levels, and reliance upon industry data becomes necessary. Staff does not recommend any change to the NS level because FPUC's proposed NS of negative 20 percent is in line with other Florida IOUs. The resulting remaining life depreciation rate is 4.0 percent for Account 368.

Account 369 – Services

This account has experienced a 5.8 percent growth rate and less than a 0.2 percent retirement rate over the study period. FPUC proposed to increase the ASL for this account from 34 years to 37 years. This increase brings the ASL closer to the average of other IOUs in the state. FPUC proposed to retain the R3 curve. Staff proposes to change the curve from R3 to R5, due to the current average asset age and retirement activity. Staff recommends a 37-year ASL with the R5 curve because it is more indicative of expected retirement dispersion. The resulting ARL is 19.9 years. FPUC concurs with staff's recommendation.

FPUC proposed to retain a NS level of negative 35 percent. This level of NS continues to be in the range of reasonableness compared to other IOUs in the state. Staff does not recommend any modification at this time. The resulting remaining life depreciation rate is 3.6 percent for Account 369.

Account 370 – Meters

FPUC proposed no change to the currently-approved ASL and curve shape. Based on a review of this account's retirement activity, and reviewing depreciation parameters prescribed to other

IOUs in the state, staff recommends that FPUC's current 30-year ASL and R5 curve combination be approved as it continues to be reasonable. The resulting ARL is 11.9 years.

FPUC proposed to change the NS level from negative 5 to negative 10 percent. The company believes a level of negative 10 percent is more in line with expected activity. Staff notes this account's actual NS level experienced over the study period is negative 13.2 percent. The average NS level of other IOUs in the state is negative 12.6 percent. Staff recommends that a NS level of negative 10 percent be approved. The resulting remaining life depreciation rate is 3.7 percent for Account 370.

Account 371 – Installation on Customers' Premises

FPUC proposed to increase the ASL from 16 to 20 years, and retain the S3 curve. This account has experienced a 17 percent growth rate and a 0.7 percent retirement rate over the study period. Staff recommends the company's proposals be approved. These modifications reflect the account's recent activity and will bring FPUC closer to the state's industry average. The resulting ARL is 9.6 years.

FPUC proposed to retain a NS level of 15 percent. Staff notes that this account has experienced an approximate negative 39 percent removal cost and zero salvage each year during the study period. Staff also notes that FPUC is the only IOU in Florida that has a positive NS for this account. The state's industry average of NS is negative 3.3 percent. Staff inquired whether the high level of negative NS (due to removal costs) during the last four years is indicative of future expectations. The company responded:

> The investment in this account is primarily commercial lighting equipment located on a customer's premise. The in-plant cost relates to the cost of the equipment and installation thereof on the customer's side of the meter. The retirement rate has averaged less than 1 percent making statistical analysis results meaningless for determining life or salvage factors.[7]

Staff agrees that lack of retirement activity renders statistical analysis inconclusive for determining life and/or salvage factors. Reliance on industry averages is therefore necessary. Staff recommends reducing the NS level of this account from 15 to 10 percent. This renders FPUC's NS level being closer to the industry average and at the same time reflects the account's current cost of removal activity. The resulting remaining life depreciation rate is 4.5 percent for Account 371.

Account 373 – Street Lighting & Signal Systems

After reviewing the information provided by the company in this docket, staff recommends a remaining life depreciation rate of 4.9 percent for Account 373.

[7] Florida Public Utilities Company's Responses to Commission Staff's First Set of Data Requests, No. 50.

General Plant – Amortizable

Below are staff's recommendations for general plant amortizable accounts, which generally constitute a continuation of FPUC's previously authorized amortizable accounts and associated periods.[8] However, in this proceeding the company has requested to combine two previously separated amortization sub-accounts, re-number two existing sub-accounts, and establish one new amortizable sub-account.[9]

The company requested to combine Accounts 391.0 – Office Furniture & Equipment with 391.2 – Office Machines. If approved, the combined property will all be classified/amortized as Account 391.0 – Office Furniture & Equipment. Both accounts are currently amortized over 7 years and no change to the period is being proposed.

The company requested re-numbering (and renaming) Account 391.1 – Office Furniture to Account 391.3 – Office Furniture & Fixtures. This property currently amortizes over 7 years and no change to the period is being proposed nor recommended. FPUC has also requested to re-number Account 391.3 – Computer Equipment, to Account 391.2 – Computer Equipment. This property currently amortizes over 5 years and no change to the period is being proposed.

The company also requested that a new sub-account of Account 391 be established. This new sub-account, Account 391.1 - Computers & Peripherals, is being proposed with an amortization period of five years. Staff recommends FPUC's request to establish Account 391.1 – Computers & Peripherals be approved by the Commission.

Table 2-1 contains staff's proposed amortization accounts and associated periods.

Table 2-1
Proposed Amortization Periods

Acct. #	Account Name	Amortization Period
391.0	Office Furniture & Equipment	7-Year Amortization
391.1	Computers & Peripherals	5-Year Amortization
391.2	Computer Equipment	5-Year Amortization
391.3	Office Furniture & Fixtures	7-Year Amortization
391.4	Software	5-Year Amortization
393	Stores Equipment	7-Year Amortization
394	Tools/Shop Equipment	7-Year Amortization
395	Lab Equipment	7-Year Amortization
397	Communications Equipment	5-Year Amortization

[8] Order No. PSC-12-0065-PAA-EI, issued February 13, 2012, in Docket No. 110207-EI, In re: 2011 depreciation study by Florida Public Utilities Company.
[9] Florida Public Utilities Company's Response to Staff's Report on FPUC's 2015 Depreciation Study, page 2.

Acct. #	Account Name	Amortization Period
397.3	Communications Equipment Post 98	5-Year Amortization
398	Miscellaneous Equipment	7-Year Amortization

General Plant - Depreciable

Account 390 – Structures & Improvements

This account experienced an approximate 196 percent investment growth over the four-year study period from 2011-2014. Staff discovered that the majority of this increase stems from the addition of costs associated with a new company office building located in Fernandina Beach to this account's investment balance.[10] Staff understands this level of addition/growth for Account 390 to be an unusual event, and that going forward the company expects this account will return to its historical growth pattern. For this reason, staff agreed with the company's proposed depreciation parameters for Account 390 – Structures & Improvements, which result in a remaining life depreciation rate of 2.0 percent.

Account 392.1 – Transportation - Cars

After reviewing the information provided by the company in this docket, staff recommends a remaining life depreciation rate of 11.9 percent for Account 392.1.

Account 392.2 – Transportation - Light Truck & Vans

After reviewing the information provided by the company in this docket, staff recommends a remaining life depreciation rate of 7.8 percent for Account 392.2.

Account 392.3 – Transportation - Heavy Trucks

After reviewing the information provided by the company in this docket, staff recommends a remaining life depreciation rate of 7.0 percent for Account 392.3.

Account 392.4 – Transportation - Trailers

After reviewing the information provided by the company in this docket, staff recommends a remaining life depreciation rate of 3.7 percent for Account 392.4.

Account 396 – Power Operated Equipment

After reviewing the information provided by the company in this docket, staff recommends a remaining life depreciation rate of 4.4 percent for Account 396.

[10] Florida Public Utilities Company's Responses to Commission Staff's First Set of Data Requests, No. 57.

Issue 3: What, if any, corrective reserve allocations should be made?

Recommendation: Staff recommends the reserve allocations shown in Attachment C. These allocations bring these accounts more in line with their theoretically correct reserve levels. (Higgins)

Staff Analysis: As part of its review of FPUC's depreciation study, staff reviewed the book reserve (accumulated depreciation) position relative to total investment for each account. Based on staff's recommended life and salvage parameters for this study, staff determined FPUC's theoretical or calculated reserve. The difference between an account's book and calculated reserve may be described as a positive or negative imbalance, or as a surplus or deficiency. When negative or positive imbalances occur, as was the case in FPUC's prior depreciation filing, the Commission found that corrective transfers should be considered and implemented as appropriate.[11]

Staff's proposed reserve transfers are based on analysis of FPUC's reserve imbalances and responses to staff data requests. Staff is in agreement with the company on all recommended reserve transfers, which are shown on Attachment C.[12]

[11] Order No. PSC-12-0065-PAA-EI, issued February 13, 2012, in Docket No. 110207-EI, In re: 2011 depreciation study by Florida Public Utilities Company.
[12] Florida Public Utilities Company's Response to Staff's Report on FPUC's 2015 Depreciation Study, page 3, and Schedule 5 (revised 10/20/2015).

Issue 4: If the Commission votes in Issue 1 to change FPUC's depreciation rates and amortization schedules, what should be the implementation date for FPUC's revised depreciation rates and amortization schedules that may be approved in Issue 2?

Recommendation: Staff recommends approval of FPUC's proposed January 1, 2015, date of implementation for the company's revised depreciation rates. (Higgins)

Staff Analysis: Rule 25-6.0436(6)(b), F.A.C., requires that the data submitted in a depreciation study, including plant and reserve balances or company estimates, "shall be brought to the effective date of the proposed rates." The supporting data and calculations provided by FPUC match an implementation date of January 1, 2015. Therefore, if the Commission votes in Issue 1 to change FPUC's depreciation rates and amortization schedules, staff recommends the Commission find January 1, 2015 as the appropriate date for implementing any new depreciation rates and amortizations for FPUC's investments that may be approved in Issue 2.

Issue 5: Should the current amortization of investment tax credits (ITCs) and flow back of excess deferred income taxes (EDITs) be revised to reflect the approved depreciation rates and amortizations schedules?

Recommendation: Yes. The current amortization of ITCs should be revised to match the actual recovery periods for the related property. The company should file detailed calculations of the revised ITC amortization at the same time it files its earnings surveillance report covering the period ending December 31, 2015, as specified in Rule 25-6.1352, F.A.C. (Cicchetti)

Staff Analysis: In Issue 2, staff has recommended approval of revised depreciation rates for the company, to be effective January 1, 2015, which reflect changes to most accounts' remaining lives to be effective January 1, 2015. Revising a utility's book depreciation lives generally results in a change in its rate of ITC amortization in order to comply with the normalization requirements of the Internal Revenue Code (IRC or Code) set forth in sections 168(f)(2) and (i)(9),[13] IRC section 167(l),[14] former IRC Section 46(f),[15,16] Federal Tax Regulations under the Code sections,[17] and section 203(e) of the Tax Reform Act of 1986 (the Act).[18]

Staff, the Internal Revenue Service (IRS), and independent outside auditors look at a company's books and records, and the orders and rules of the jurisdictional regulatory authorities to determine if the books and records are maintained in the appropriate manner. The books are also reviewed to determine if they are in compliance with the regulatory guidelines in regard to normalization.

Former Section 46(f)(6) of the Code indicated that the amortization of ITC should be determined by the period of time actually used in computing depreciation expense for ratemaking purposes and on the regulated books of the utility.[19] Since staff is recommending changes to the company's remaining lives, it is also important to change the amortization of ITCs to avoid violation of the provisions of former IRC section 46 and its underlying Treasury Regulations. The consequence of an ITC normalization violation is a repayment of unamortized ITC balances to the IRS. Therefore, staff recommends the current amortization of ITCs should be revised to match the actual recovery periods for the related property. The company should file detailed calculations of the revised ITC amortization at the same time it files its earnings surveillance report covering the period ending December 31, 2015, as specified in Rule 25-6.1352, F.A.C.

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[13] 26 USC §§168(f)(2) and (i)(9).
[14] 26 USC §167(l).
[15] 26 USC §46(f), repealed by Revenue Reconciliation Act of 1991, Pub. L. No. 101-508, §11812(a)(1-2)(1990).
[16] Under IRC Section 50(d)(2), the terms of former IRC section 46(f) remain applicable to public utility property for which a regulated utility previously claimed ITCs, which is the case here. (I.R.S. Priv. Ltr. Rul. 200933023, 1n.1 (May 7, 2009)).
[17] Treas. Reg. §1.168; Treas. Reg. §1.167; Treas. Reg. §1.46.
[18] Tax Reform Act of 1986, Pub. L. No. 99-514 (100 Stat. 2085, 2146)(1986).
[19] See 26 USC §46(f)(6) (establishing proper determination of ratable portion).

Issue 6: 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, this docket should be closed upon the issuance of a consummating order. (Leathers)

Staff Analysis: At the conclusion of the protest period, if no protest is filed, this docket should be closed upon the issuance of a consummating order.

Attachment A

Comparison of Rates and Components

Account Number	Account Title	Currently Approved[20] Average Remaining Life (yrs.)	Currently Approved[20] Future Net Salvage (%)	Currently Approved[20] Remaining Life Rate (%)	Staff Recommended Average Remaining Life (yrs.)	Staff Recommended Reserve (%)		Staff Recommended Future Net Salvage (%)	Staff Recommended Remaining Life Rate (%)
	TRANSMISSION PLANT								
350.1	Land Rights	25.0	0	2.3	26.0	63.60	*	0	1.4
352	Structures and Improvements	29.0	0	1.8	50.0	8.86		0	1.8
353	Station Equipment	23.0	10	2.4	27.0	25.30		5	2.6
354	Towers and Fixtures	17.6	(15)	2.1	14.5	84.65		(15)	2.1
355	Poles and Fixtures	19.3	(30)	3.4	16.9	70.82	*	(40)	4.1
355.1	Poles and Fixtures - Concrete	40.0	(30)	2.9	41.0	11.10	*	(30)	2.9
356	Overhead Conductors and Devices	31.0	(10)	2.4	36.0	29.35		(20)	2.5
359	Roads and Trails	15.5	0	1.5	12.5	81.03		0	1.5
	DISTRIBUTION PLANT								
360.1	Land Rights	30.0	0	1.8	31.0	51.83		0	1.6
361	Structures and Improvements	46.0	(5)	1.9	47.0	23.65		(5)	1.7
362	Station Equipment	30.0	(10)	2.8	34.0	28.40	*	(10)	2.4
364	Poles, Towers, and Fixtures	23.0	(45)	4.1	24.0	50.28	*	(45)	3.9
365	Overhead Conductors & Devices	17.2	(35)	4.1	21.0	63.60	*	(35)	3.4
366	Underground Conduit	49.0	0	1.6	50.0	15.00	*	(5)	1.8
367	Underground Conductors & Devices	23.0	0	2.9	23.0	32.11		(5)	3.2
368	Line Transformers	12.0	(20)	4.3	12.4	70.40	*	(20)	4.0
369	Services	20.0	(35)	4.0	19.9	63.36	*	(35)	3.6
370	Meters	13.2	(5)	3.7	11.9	65.97	*	(10)	3.7
371	Installation on Customers' Premises	7.2	15	5.7	9.6	46.80	*	10	4.5
373	Street Lighting & Signal Systems	8.9	(10)	5.0	7.6	72.94		(10)	4.9
	GENERAL PLANT								
390	Structures & Improvements	31.0	0	2.0	41.0	16.67		0	2.0
391.0	Office Furniture & Equipment	7-Year Amortization			7-Year Amortization				
391.1	Computers & Peripherals	N/A			5-Year Amortization				
391.2	Computer Equipment[21]	5-Year Amortization			5-Year Amortization				
391.3	Office Furniture & Fixtures[22]	7-Year Amortization			7-Year Amortization				
391.4	Software	5-Year Amortization			5-Year Amortization				
392.1	Transportation - Cars	0.0	15	12.1	6.0	13.41		15	11.9

[20] Order No. PSC-12-0065-PAA-EI, issued February 13, 2012, in Docket No. 110207-EI, In re: 2011 depreciation study by Florida Public Utilities Company.
[21] Listed as Account 391.3 in Order No. PSC-12-0065-PAA-EI, issued February 13, 2012, in Docket No. 110207-EI, In re: 2011 depreciation study by Florida Public Utilities Company.
[22] Listed as Account 391.1 (Office Furniture) in Order No. PSC-12-0065-PAA-EI, issued February 13, 2012, in Docket No. 110207-EI, In re: 2011 depreciation study by Florida Public Utilities Company.

Attachment A

Comparison of Rates and Components

Account Number	Account Title	Currently Approved[20] Average Remaining Life (yrs.)	Currently Approved[20] Future Net Salvage (%)	Currently Approved[20] Remaining Life Rate (%)	Staff Recommended Average Remaining Life (yrs.)	Staff Recommended Reserve (%)	Staff Recommended Future Net Salvage (%)	Staff Recommended Remaining Life Rate (%)
	TRANSMISSION PLANT							
392.2	Transportation - Light Trucks & Vans	2.9	12	9.8	4.9	49.90	12	7.8
392.3	Transportation - Heavy Trucks	7.0	10	6.6	6.4	45.29	10	7.0
392.4	Transportation - Trailers	13.9	5	3.8	13.8	44.38	5	3.7
393	Stores Equipment	7-Year Amortization			7-Year Amortization			
394	Tools/Shop Equipment	7-Year Amortization			7-Year Amortization			
395	Lab Equipment	7-Year Amortization			7-Year Amortization			
396	Power Operated Equipment	5.5	0	2.8	8.4	63.23	0	4.4
397	Communications Equipment	5-Year Amortization			5-Year Amortization			
397.3	Communications Equipment Post 98	5-Year Amortization			5-Year Amortization			
398	Miscellaneous Equipment	7-Year Amortization			7-Year Amortization			

*Denotes a Reserve Transfer

Attachment B

		Comparison of Expenses Current[23]		Staff Proposed		
Account Number	Account Title	Depreciation Rate (%)	Annual Expense ($)	Depreciation Rate (%)	Annual Expense ($)	Change In Expense ($)
	TRANSMISSION PLANT					
350.1	Land Rights	2.3	548	1.4	334	(215)
352	Structures and Improvements	1.8	3,560	1.8	3,560	0
353	Station Equipment	2.4	89,965	2.6	97,462	7,497
354	Towers and Fixtures	2.1	4,721	2.1	4,721	0
355	Poles and Fixtures	3.4	53,662	4.1	64,710	11,048
355.1	Poles and Fixtures - Concrete	2.9	77,032	2.9	77,032	0
356	Overhead Conductors and Devices	2.4	60,906	2.5	63,443	2,538
359	Roads and Trails	1.5	102	1.5	102	0
	TOTAL TRANSMISSION PLANT		290,495		311,363	20,868
	DISTRIBUTION PLANT					
360.1	Land Rights	1.8	1,026	1.6	912	(114)
361	Structures and Improvements	1.9	3,307	1.7	2,959	(348)
362	Station Equipment	2.8	247,926	2.4	212,508	(35,418)
364	Poles, Towers, and Fixtures	4.1	584,109	3.9	555,615	(28,493)
365	Overhead Conductors & Devices	4.1	537,261	3.4	445,533	(91,727)
366	Underground Conduit	1.6	88,818	1.8	99,920	11,102
367	Underground Conductors & Devices	2.9	236,535	3.2	261,004	24,469
368	Line Transformers	4.3	724,774	4.0	674,209	(50,566)
369	Services	4.0	407,483	3.6	366,735	(40,748)
370	Meters	3.7	144,806	3.7	144,806	0
371	Installation on Customers' Premises	5.7	173,473	4.5	136,953	(36,521)
373	Street Lighting & Signal Systems	5.0	72,306	4.9	70,860	(1,446)
	TOTAL DISTRIBUTION PLANT		3,221,824		2,972,014	(249,810)
	GENERAL PLANT					
390	Structures & Improvements	2.0	89,801	2.0	89,801	0
392.1	Transportation - Cars	12.1	6,089	11.9	5,989	(101)
392.2	Transportation - Light Trucks & Vans	9.8	94,153	7.8	74,938	(19,215)
392.3	Transportation - Heavy Trucks	6.6	233,285	7.0	247,423	14,138
392.4	Transportation - Trailers	3.8	5,475	3.7	5,331	(144)
396	Power Operated Equipment	2.8	8,483	4.4	13,331	4,848
	TOTAL GENERAL PLANT		437,288		436,814	(474)
	TOTAL PLANT		3,949,607		3,720,192	(229,415)

[23] Order No. PSC-12-0065-PAA-EI, issued February 13, 2012, in Docket No. 110207-EI, In re: 2011 depreciation study by Florida Public Utilities Company.

Attachment C

Theoretical Reserve Analysis

Account Number	Account Title	Reserve 1/1/2015 ($)	Theoretical Reserve ($)	Reserve Imbalance ($)	Reserve Transfer ($)	Restated Reserve ($)
	TRANSMISSION PLANT					
350.1	Land Rights	18,962	15,163	3,799	(3,799)	15,163
352	Structures and Improvements	17,516	19,776	(2,260)	0	17,516
353	Station Equipment	948,485	1,132,053	(183,568)	0	948,485
354	Towers and Fixtures	190,300	190,070	230	0	190,300
355	Poles and Fixtures	1,073,934	1,276,052	(202,118)	43,786	1,117,720
355.1	Poles and Fixtures - Concrete	334,834	294,847	39,987	(39,987)	294,847
356	Overhead Conductors and Devices	744,898	852,680	(107,782)	0	744,898
359	Roads and Trails	5,500	5,515	(15)	0	5,500
	TOTAL TRANSMISSION PLANT	3,334,429	3,786,156	(451,727)	0	3,334,429
	DISTRIBUTION PLANT					
360.1	Land Rights	29,540	26,959	2,581	0	29,540
361	Structures and Improvements	41,158	35,502	5,656	0	41,158
362	Station Equipment	2,682,209	2,514,680	167,529	(167,529)	2,514,680
364	Poles, Towers, and Fixtures	6,805,379	7,664,645	(859,266)	357,983	7,163,362
365	Overhead Conductors & Devices	8,358,899	8,334,096	24,803	(24,803)	8,334,096
366	Underground Conduit	952,686	832,669	120,017	(120,017)	832,669
367	Underground Conductors & Devices	2,619,264	2,936,293	(317,029)	0	2,619,264
368	Line Transformers	11,953,804	11,866,072	87,732	(87,732)	11,866,072
369	Services	6,560,065	6,454,535	105,530	(105,530)	6,454,535
370	Meters	2,285,299	2,581,858	(296,559)	296,559	2,581,858
371	Installation on Customers' Premises	1,573,237	1,424,306	148,931	(148,931)	1,424,306
373	Street Lighting & Signal Systems	1,054,774	1,041,213	13,561	0	1,054,774
	TOTAL DISTRIBUTION PLANT	44,916,314	45,712,828	(796,515)	0	44,916,314
	GENERAL PLANT					
390	Structures & Improvements	748,472	808,211	(59,739)	0	748,472
392.1	Transportation - Cars	6,747	6,240	507	0	6,747
392.2	Transportation - Light Trucks & Vans	479,394	384,107	95,287	0	479,394
392.3	Transportation - Heavy Trucks	1,600,669	1,620,269	(19,600)	0	1,600,669
392.4	Transportation - Trailers	63,950	61,322	2,628	0	63,950
396	Power Operated Equipment	191,566	201,179	(9,613)	0	191,566
	TOTAL GENERAL PLANT	3,090,798	3,081,328	9,470	0	3,090,798
	TOTAL PLANT	51,341,541	52,580,312	(1,238,771)	0	51,341,541

Item 11

FILED NOV 18, 2015
DOCUMENT NO. 07293-15
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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Higgins) WBM
Office of the General Counsel (Villafrate)

RE: Docket No. 150208-EI – Petition for base rate reduction reflecting end of amortization period for retired plant, by Florida Power & Light Company.

AGENDA: 12/03/15 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brisé

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On September 18, 2015, Florida Power and Light Company (FPL or company) filed a petition to reduce its jurisdictional annual revenue requirement by $222,192 in accordance with the Nuclear Cost Recovery (NCR) process set forth in Section 366.93, Florida Statutes (F.S.). FPL states that this proposed revenue requirement reduction reflects the end of the Commission-authorized five-year amortization of the true-up of the final net book value of plant retired in 2009, as well as the actual/estimated net book value of plant retired in 2010, associated with FPL's Extended Power Uprate Project (EPU).[1] The amortization for both of these costs began in March 2011. FPL is requesting to implement its revised annual revenue requirement on March 1, 2016.

[1] Order No. PSC-08-0021-FOF-EI, issued January 7, 2008, Docket No. 070602-EI, In re: Petition for determination of need for expansion of Turkey Point and St. Lucie nuclear power plants, for exemption from Bid Rule 25-22.082, Florida Administrative Code (F.A.C.), and for cost recovery through the Commission's Nuclear Power Plant Cost Recovery Rule, Rule 25-6.0423, F.A.C.

In 2006, the Florida Legislature adopted legislation, Section 366.93, F.S., encouraging the development of nuclear energy in the state. In that section, the Legislature directed the Commission to adopt rules providing for alternative cost recovery mechanisms that would encourage investor-owned electric utilities to invest in nuclear power plants. The Commission adopted Rule 25-6.0423, Florida Administrative Code (F.A.C.), which provides for an annual cost recovery proceeding to consider investor-owned utilities' requests for cost recovery for nuclear plants.

By Order No. PSC-08-0021-FOF-EI,[2] the Commission made an affirmative determination of need for FPL's proposed EPU project to expand all four of its nuclear units: Turkey Point Units 3 and 4 and St. Lucie Units 1 and 2. Staff notes this work has been performed and all four EPU projects are complete.

Pursuant to Rule 25-6.0423(8)(e), F.A.C.,[3] FPL requested to increase its base rates in 2009 to recover the costs of assets retired that same year because of the EPU Project. The Rule states:

> The jurisdictional net book value of any existing generating plant that is retired as a result of operation of the power plant shall be recovered through an increase in base rate charges over a period not to exceed 5 years. At the end of the recovery period, base rates shall be reduced by an amount equal to the increase associated with the recovery of the retired generating plant.

By Order No. PSC-10-0207-PAA-EI,[4] the Commission authorized FPL to increase its base rates for recovering costs associated with the turbine gantry crane phase of the EPU project at St. Lucie Unit 2. This authorization and approval was subject to true-up and revision based on a final review of the associated expenditures in the Nuclear Cost Recovery Clause, Docket No. 100009-EI.

By Order No. PSC-11-0078-PAA-EI[5] the Commission approved FPL's request for a 5-year amortization to recover the net book value of retired plant related to the company's EPU Project in the amount of $198,307 (jurisdictional). Order No. PSC-11-0078-PAA-EI also directed the company to include the true-up revision required by Order No. PSC-10-0207-PAA-EI. This true-up resulted in an additional increase to base rates of $48,335. Of this amount $23,885 related to recovery of retirement, removal, and salvage of plant equipment costs under Rule 25-

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[2] Ibid.

[3] Rule 25-6.0423, F.A.C., Nuclear or Integrated Gasification Combined Cycle Power Plant Cost Recovery, was last amended on 1/29/2014. The Rule amendment occurred subsequent to FPL's petition in Docket No. 100419-EI. In it's petition, FPL requested, and the Commission ultimately ordered in Order No. PSC-11-0078-PAA-EI, recovery under Rule 25-6.0423(7), F.A.C. Due the January 2014 amendment, Rule 25-6.0423(7), F.A.C., was re-numbered to Rule 25-6.0423(8), F.A.C. Staff refers to the current numbering of Rule 25-6.0423, F.A.C., throughout this recommendation, however, has left intact the original docket names/references in footnotes.

[4] Order No. PSC-10-0207-PAA-EI, issued April 5, 2010, in Docket No. 090529-EI, In re: Petition to include costs associated with the extended power uprate project in base rates, by Florida Power & Light Company.

[5] Order No. PSC-11-0078-PAA-EI, issued January 31, 2011, in Docket No. 100419-EI, In re: Petition for approval of base rate increase for extended power uprate systems placed in commercial service, pursuant to Section 366.93(4), F.S., and Rules 25-6.0423(7) and 28-106.201, F.A.C., by Florida Power & Light Company.

6.0423(8)(e), F.A.C., was set for 5-year amortization. The combined amount of $198,307 and $23,885, or $222,192, began being amortized March 1, 2011.[6] The company now requests authorization in the instant docket to reflect conclusion of the amortization by reducing its annual revenue requirement by $222,192.

The Commission has jurisdiction over these matters through several provisions of Chapter 366, F.S., including Sections 366.05 and 366.06, F.S.

[6] Ibid.

Discussion of Issues

Issue 1: Should the Commission approve FPL's request to decrease its annual revenue requirement by $222,192 to reflect the conclusion of the 5-year asset amortization, which began in March 2011, for recovery of assets retired in 2009 and 2010 because of the company's EPU project?

Recommendation: Yes. The Commission should approve FPL's request to decrease its annual revenue requirement by $222,192 to reflect the conclusion of the 5-year asset amortization, which began in March 2011, for recovery of assets retired in 2009 and 2010 because of the company's EPU project. (Higgins)

Staff Analysis: By Order No. PSC-11-0078-PAA-EI,[7] the Commission approved FPL's request to increase its base rates by $222,192 for the 5-year asset amortization, which began in March 2011, for recovery of assets retired in 2009 and 2010 because of the company's EPU project. FPL's petition in this docket requesting the Commission approve a decrease of its annual revenue requirement by $222,192 is consistent with that order.

Due to the pending conclusion of the 5-year amortization period, staff recommends the Commission approve FPL's request to reduce its revenue requirement by $222,192. If approved, staff notes that FPL's newly revised revenue requirement will not require any tariff revisions, or change in rates, due to the minimal decrease when appropriately allocated across all of FPL's rate classes.[8] A summary of FPL's proposed revised annual revenue requirement allocated across all rate classes is contained on Attachment B to its petition, which as previously mentioned lists no change in rates for all customer classes.

Conclusion

Staff recommends the Commission approve FPL's request to decrease its annual revenue requirement by $222,192 to reflect the conclusion of the 5-year asset amortization, which began in March 2011, for recovery of assets retired in 2009 and 2010 because of the company's EPU project.

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[7] Order No. PSC-11-0078-PAA-EI, issued January 31, 2011, in Docket No. 100419-EI, In re: Petition for approval of base rate increase for extended power uprate systems placed in commercial service, pursuant to Section 366.93(4), F.S., and Rules 25-6.0423(7) and 28-106.201, F.A.C., by Florida Power & Light Company.

[8] The total revenue requirements were allocated based on the nuclear revenue requirements in the Cost of Service Study approved by Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 120015-EI, In re: Petition for increase in rates by Florida Power & Light Company.

Issue 2: What is the effective date of FPL's revised revenue requirement?

Recommendation: If the Commission approves the staff recommendation in Issue 1, the revised revenue requirement for FPL should be implemented beginning March 1, 2016. (Higgins)

Staff Analysis: By Order No. PSC-11-0078-PAA-EI[9] the Commission approved FPL's request to increase its base rates for a period of 5 years via amortization to recover the net book value of retiring plant related to the Company's EPU Project. The 5-year amortization period began March 1, 2011. Under Commission rule,[10] the net book value of any existing generating plant that is retired shall be recovered through an increase in base rate charges over a period not to exceed 5 years. Staff notes that the five-year period from inception ends March 1, 2016, which is also the date FPL is requesting to implement its revised revenue requirement. Therefore, staff believes the appropriate date for FPL to revise its revenue requirement by $222,192 is March 1, 2016.

Conclusion

If the Commission approves the staff recommendation in Issue 1, the revised revenue requirement for FPL should be implemented beginning March 1, 2016.

[9] Order No. PSC-11-0078-PAA-EI, issued January 31, 2011, in Docket No. 100419-EI, In re: Petition for approval of base rate increase for extended power uprate systems placed in commercial service, pursuant to Section 366.93(4), F.S., and Rules 25-6.0423(7) and 28-106.201, F.A.C., by Florida Power & Light Company.
[10] Rule 25-6.0423(8)(e), F.A.C.

Issue 3: 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, this docket should be closed upon the issuance of a consummating order. (Villafrate)

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, this docket should be closed upon the issuance of a consummating order.

Item 12

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Wu, Stratis)
Division of Engineering (Graves, Wooten)
Office of the General Counsel (Mapp)
Office of Industry Development and Market Analysis (Clemence)

RE: Docket No. 150211-EI – Petition for approval of depreciation rates for solar photovoltaic generating units, by Tampa Electric Company.

AGENDA: 12/03/15 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brown

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

Pursuant to Rule 25-6.0436(3)(a), Florida Administrative Code (F.A.C.), electric utilities are required to maintain depreciation rates and accumulated depreciation reserve in accounts or subaccounts as prescribed in Rule 25-6.014(1), F.A.C. Rule 25-6.0436(3)(b), F.A.C., provides that "[u]pon establishing a new account or subaccount classification, each utility shall request Commission approval of a depreciation rate for the new plant category." On September 29, 2015, Tampa Electric Company (TECO or the company) filed its petition, in accordance with this rule, to establish depreciation rates for its solar photovoltaic generating units and associated equipment. The Florida Public Service Commission (Commission) has jurisdiction in this matter pursuant to Sections 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

Discussion of Issues

Issue 1: Should the Commission establish subaccounts with depreciation rates for TECO's solar photovoltaic generating units and associated equipment?

Recommendation: Yes. Staff recommends the Commission establish the subaccounts shown in the staff analysis, with a 30-year life and a whole life depreciation rate of 3.3 percent, for TECO's solar photovoltaic generating units and associated equipment. (Wu, Clemence, Graves, Stratis, Wooten)

Staff Analysis: TECO is seeking the Commission's approval of depreciation rates for specified subaccounts to apply to solar photovoltaic (PV) generating units and associated equipment that it is constructing at the Tampa International Airport (TIA), and to such other solar PV generating systems expected to be constructed in the future. The TIA project involves construction of a 2 MW_{DC} PV system located on the top floor of TIA's Economy Parking Garage. TECO will own the PV support structure, PV system and the energy output under a 25-year lease from TIA for the space. Commissioning of the generating units is expected in late December 2015. Other solar PV projects[1] are expected in the future.

In Order No. PSC-08-0731-PAA-EI,[2] the Commission adopted a 30-year life with zero net salvage for comparable solar PV generating units for Florida Power & Light Company (FPL). The resulting 3.3 percent depreciation rate was authorized in that order to be used for the following subaccounts:[3]

303.xx Intangible Plant

341.xx Structures and Improvements

343.xx Other Generation Plant

345.xx Accessory Electric Equipment

TECO plans to use the same subaccounts to book all the components of its solar PV generating units that are currently under construction and will be built in the future. TECO also believes that a 30-year plant life, a zero net salvage, and a 3.3 percent depreciation rate applies to these same depreciation subaccounts for the company's solar PV facilities. TECO indicates that it has very little experience with large utility scale solar PV generating facilities and their expected life and depreciation rate. TECO determined that the aforementioned subaccounts with a 3.3 percent

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[1] TECO's petition, page 2, indicates that the company is investigating a 25 MW_{DC} PV system to be sited near the Big Bend Station and the Manatee Viewing Center.

[2] Order No. PSC-08-0731-PAA-EI, issued November 3, 2008, in Docket 080543-EI. In re: Request for approval to begin depreciating new technology solar photovoltaic plant sites for DeSoto and Space Coast Solar Energy Centers over 30-year period, effective with in-service dates of units, by Florida Power & Light Company.

[3] TECO intends to record solar PV generating units in subaccounts so that the investments in these assets will be separately identified within TECO's plant accounts. At this time TECO has not yet identified the specific subaccounts in which to record these investments; however, the subaccounts will be set up prior to the in-service date of any solar PV units.

depreciation rate granted to FPL's solar PV generating units by the Commission seemed appropriate for the TECO facilities.[4]

The major components of the solar PV generating system include PV panels, inverters and a support structure. Staff notes that Solar Electric Power Association, a solar research and education non-profit entity with electric utility and company members, and Solar Source, the TIA project turnkey construction firm, concurred with TECO's proposed 30-year plant life. In addition, National Renewable Energy Laboratory's 25 to 40 years estimated life supports TECO's estimated 30-year plant life.[5] Staff notes that the PV panels used for this project[6] have a 25-year linear performance warranty. The inverters have 15-year warranty, but the company anticipates replacing the inverters once during the life of the system. The support structure is concrete canopy which was built to meet or exceed the expected facility life.[7] The lease entered into between TECO and TIA for space to locate the PV generating units is for 25 years with a 5-year extension option. It is TECO's intent to exercise the option to extend the lease for an additional 5 years for a total of 30 years from the commencement date of the TIA solar PV generating units.[8]

TECO proposes a net salvage value of zero for the petitioned subaccounts to book its PV generating units and associated equipment. The company indicates that it does not know the salvage value this early in the development of utility scale solar PV generating stations.[9] The company proposes a net salvage value of zero until a better understanding of net salvage value is known. As better understanding is gained over the years, this value can be re-evaluated. Staff agrees with TECO's position. Rule 25-6.0436(8)(a), F.A.C., requires investor-owned utilities to file a comprehensive depreciation study at least once every four years from the submission date of the previous study. The values of the net salvage as well as other depreciation parameters assigned to the petitioned subaccounts in the instant case will be re-evaluated in TECO's future depreciation studies filed with the Commission.

In its petition, TECO indicates that it is currently evaluating the retirement unit structure that the company will employ and will prepare and file a site specific depreciation study for TIA. The company explains that the first couple of utility scale solar PV generating sites being considered have some substantial differences in construction and siting between them, so site-specific depreciation studies may be called for until some understanding of comparable construction and siting become apparent for future development.[10] The filing of the TIA site study would occur some time after the facility goes into service and all the trailing charges have been booked and unitized.

Based on the information available and the analysis above, staff believes that TECO's proposed 30-year life and zero net salvage for solar PV generating units applied to the subaccounts

[4] TECO's responses to Staff's First Data Request Nos. 5.b. and 10.
[5] TECO's response to Staff's First Data Request No. 1.
[6] SW325 PV panels manufactured by SolarWorld.
[7] TECO's response to Staff's First Data Request No. 2
[8] TECO's response to Staff's First Data Request No. 3.
[9] TECO's response to Staff's First Data Request No. 9.
[10] TECO's response to Staff's First Data Request No. 11.

identified on page 2 are appropriate at this time. This results in a whole life depreciation rate of 3.3 percent.

Conclusion

Staff believes it would be appropriate for the Commission establish the Subaccounts 303.xx-Intangible Plant, 341.xx-Structures and Improvements, 343.xx-Other Generation Plant, and 345.xx-Accessory Electric Equipment, with a 30-year life and a whole life depreciation rate of 3.3 percent, for TECO's solar photovoltaic generating units and associated equipment.

Issue 2: What should be the effective date for the implementation of the new depreciation rates for TECO's solar photovoltaic generating units and associated equipment?

Recommendation: Staff recommends an effective date for the implementation of the new depreciation rates for TECO's solar photovoltaic generating units and associated equipment of December 31, 2015. (Wu)

Staff Analysis: Depreciation is the recovery of invested capital representing equipment that is providing service to the public. This recovery is designed to take place over the related period of service to the public, which begins with the equipment's in-service date. In its petition, TECO has requested the Commission to approve the new depreciation rates for solar PV generating units and associated equipment effective December 3, 2015. TECO also indicated that the commissioning of the TIA solar PV generating units, the company's first solar PV plant, will be in late December 2015. Through discussion with the company,[11] staff determined that an effective date of December 31, 2015, would meet TECO's need of having approved depreciation rates for plant in-service in 2015 for reporting purposes while also recognizing the expected timing of the commissioning of the solar PV project.

[11] Document No. 07071-15.

Issue 3: 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, this docket should be closed upon the issuance of a consummating order. (Mapp)

Staff Analysis: At the conclusion of the protest period, if not protest is filed, this docket should be closed upon the issuance of a consummating order.

Item 13

FILED NOV 18, 2015
DOCUMENT NO. 07298-15
FPSC - COMMISSION CLERK

State of Florida

Public Service Commission

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

15 NOV 18 AM 9:58
COMMISSION CLERK
RECEIVED-FPSC

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

DATE: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Ollila, Guffey) A.O. S.K.G. ED
Office of the General Counsel (Corbari) KFC
Office of Industry Development and Market Analysis (Clemence) MA

RE: Docket No. 150213-EI – Petition for approval of advanced meter program agreement, by Tampa Electric Company.

AGENDA: 12/03/15 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On October 2, 201~~6~~ 5, Tampa Electric Company (Tampa Electric or Company) filed a petition for approval of its voluntary Advanced Meter Program (AMP or program) agreement tariff. Residential Tampa Electric customers who own solar photovoltaic (PV) systems interconnected with Tampa Electric are eligible for this program.

In its petition, Tampa Electric requested that the Commission approve the proposed tariff effective December 3, 2015. Tampa Electric responded to Staff's First Data Request on October 27, 2015, and to Staff's Second Data Request on November 3, 2015. The proposed tariff is provided in Attachment 1. The Commission has jurisdiction over this matter pursuant to Section 366.04, Florida Statutes.

Discussion of Issues

Issue 1: Should the Commission approve Tampa Electric's proposed AMP agreement tariff?

Recommendation: Yes, the Commission should approve Tampa Electric's proposed AMP agreement tariff effective December 3, 2015. (Ollila, Guffey, Clemence)

Staff Analysis: AMP is a voluntary program for residential customers who own PV systems that are interconnected with the Company. The signed AMP agreement permits Tampa Electric to install an advanced meter, at no cost to the customer, that will record the energy output of the customer's PV generator. The data generated by the advanced meter will be available to both the customer and the Company. Currently, customers who have installed rooftop solar PV systems do not have utility meters measuring the output of their generators. The current billing meter registers the energy purchased from Tampa Electric and the amount of excess energy from the PV system that is delivered to the Company but does not track how much of the customer's consumption is offset by the PV generator.

AMP Details

Agreement

The proposed AMP agreement has an initial term of three years. Tampa Electric states that, if a customer wishes to terminate the agreement prior to the completion of the initial term, the Company will remove the advanced meter at no cost or penalty to the customer. According to the Company, only the property owner may execute the agreement to participate in the program. If a participating customer sells the house while the agreement is in effect, the new owner of the house would be required to enter into a new agreement with Tampa Electric in order to participate in the program.

Costs

Tampa Electric estimates up-front costs of $566,000 and annual expenses of $19,500, assuming approximately 100 customers elect to participate. Up-front costs include the capital costs of the AMP meters and installation. Annual expenses include communications and web-hosting costs for the AMP meters. The Company considers AMP-related costs to be base rate costs, so there will be no costs charged to participating customers during the initial term. Tampa Electric states that, if it were to charge for AMP after the initial term, it would seek Commission approval prior to the imposition of any charge.

Customers

As of September 30, 2015, Tampa Electric had 637 residential customers who own PV systems that are interconnected with the Company. Customers will be solicited to participate via email, reaching the approximately 500 customers with email addresses on file with the Company. Tampa Electric, however, will also accept those customers without email addresses on file into the program. Tampa Electric expects about 20 percent of the customers, or 100, to participate in the program. Tampa Electric explained that it is only seeking a portion of the eligible customers to participate in the program as it believes this strategy will secure sufficient participation level for purposes of this program. Although AMP is limited to residential customers, the Company stated that the program could be expanded to commercial PVcustomers at a later date.

Meters and Installation

The AMP meter will be installed at the participant's home at or near the existing Tampa Electric-owned disconnect switch located between the participant's PV system and the delivery of the PV energy to the home. A customer requesting to participate in the AMP program will have to schedule an appointment with a Tampa Electric representative who will discuss the best location for the new AMP meter, conduct an evaluation, and answer any questions the customer may have.

In addition to the installation of the AMP meter, the customer's existing billing meter will be replaced by an advanced billing meter. The advanced billing meter differs from the existing billing meter mainly in that it includes a cellular communications device. The AMP meter will communicate the output of the PV system to the advanced billing meter in 15-minute intervals. The new advanced billing meter will then communicate the data via its cellular device to the Company allowing the Company to collect the meter data remotely.

Tampa Electric states in its petition that it will also replace existing billing meters with advanced meters at some homes with no PV installations. According to Tampa Electric, the new advanced meter will allow it to evaluate the metering and communication equipment with and without PV installations and provide early testing of advanced meters. In response to staff's data request, Tampa Electric stated that it is not seeking Commission approval of the partial deployment of advanced billing meters to customers without PV generation as part of its petition. The Company notes that Commission approval is not required to change out existing billing meters to advanced billing meters. Tampa Electric stated the partial deployment of the advanced meters will be less than 5,000 meters; customers will be able to choose whether or not to participate. The Company does not have a date yet for full deployment.

AMP Data

Customers will be able to monitor the output of their PV system via a secure web portal. According to the Company, customers may wish to use the data to determine how much power their PV systems are generating as measured by the AMP meter compared to information on generator output from the PV system.

The Company states that it is concerned about not understanding the output impacts of residential solar on its grid and on its distribution system, in particular. As the use of solar continues to expand, Tampa Electric believes solar will have a more substantial impact on its load and energy forecasting process. Tampa Electric intends to use the data recorded by the AMP meter to analyze the impact of rooftop residential solar, in conjunction with residential house usage measured by the utility meter, on its distribution system for local load planning and design of the protection devices on the distribution and substation systems.

In addition, the Company will be able to measure the output characteristics of the different types of solar generators, knowing which direction faces the sun and any potential obstructions (e.g., trees or neighboring structures) in order to determine actual achieved generator output versus nameplate generator output. The Company states that a better understanding of how well solar generation will perform compared to how it might be marketed will give Tampa Electric the ability to provide more educated advice to customers considering installing rooftop solar systems. In addition, the Company expects that, with its increased understanding of the economics of rooftop solar generation, it will be able to better engage with residential solar rooftop developers and provide advice on the impact of their developments on local areas that may require distribution line capacity upgrades.

Conclusion

Staff believes that this optional program is likely to provide useful information to the Company and participating customers. Staff recommends that the Commission approve Tampa Electric's proposed AMP agreement tariff, effective December 3, 2015.

Issue 2: Should this docket be closed?

Recommendation: ~~Yes.~~ If Issue1 is approved, the tariff should become effective on December 3, 2015. If a protest is filed within 21 days of the issuance of the order, the tariff should remain in effect pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order. (Corbari)

Staff Analysis: If Issue 1 is approved, the tariff should become effective on December 3, 2015. If a protest is filed within 21 days of the issuance of the order, the tariff should remain in effect pending resolution of the protest. If no timely protest is filed, this docket should be closed upon the issuance of a consummating order.

TAMPA ELECTRIC

ORIGINAL SHEET NO. 7.310

THIS AGREEMENT for Advanced Metering Program (AMP) service is entered into this _____ day of __________, _____, ("Effective Date") between Tampa Electric Company ("Company") and ____________________ ("Customer").

IN CONSIDERATION of the mutual agreements hereinafter contained, IT IS AGREED:

1. Scope. The Company will provide AMP service to the Customer, and the Customer will receive such service in accordance with this Agreement.

2. Rules, Regulations and Rates. Florida state law and the rules, regulations and applicable rate schedules of the Company, as may be filed with and regulated by the Florida Public Service Commission ("Commission"), shall govern AMP service and are incorporated herein by reference. Such laws, rules, regulations and rate schedules are subject to change during the term of this Agreement as provided by law. Copies of current rules, regulations and applicable rate schedules are available from the Company or the Commission upon request.

3. Term. The initial term of this Agreement shall be three (3) years from the commencement of service under this Agreement. The Agreement shall continue in effect upon completion of the initial term until terminated by either party providing written notice to the other.

4. AMP Service. The characteristics of AMP Service are:

a. The Company will install an advanced meter set on the Customer side of the existing AC disconnect switch near existing Company billing meter at the Customer's premises. The equipment installed will include all connection points between the Customer's electrical panel, the advanced meter, and associated disconnect switch conduit. The advanced meter and associated equipment installed will not interfere with the operation or maintenance of either the Customer's solar array or the associated inverter. The advanced meter and equipment will remain the property of the Company.

b. The advanced meter is designed to extract data on the Customer's solar output of Customer's solar array, and relay it back to the Company.

c. The data extracted from the advanced meter will be made available to the Customer through a website so that Customer can use the data to compare to solar generating data it collects through other means.

d. The Company will be allowed to use the solar production data from the advanced meter for utility system planning, load and generation forecasting and other business needs.

Continued on Sheet No. 7.315

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

ORIGINAL SHEET NO. 7.315

TAMPA ELECTRIC

Continued from Sheet No. 7.310

5. No Charge. The Company will bear all costs associated with the advanced meter set, its installation and repair. The Customer will not be assessed any charges by the Company for AMP service during the term of this agreement.

6. As-Available Nature of Program; No Warranty. As this is a free service, the Company reserves the right to suspend or terminate AMP Service and/or the online website in its sole discretion at any time. All data is provided as-is, as-available. The Company makes no warranty as to the availability or accuracy of the data provided through the advanced meter set and website, since it is being supplied for informational purposes only, at no charge to the Customer. The Company disclaims all warranties, express or implied, including warranties of fitness for a particular purpose.

7. Meter Access and Removal. The Customer hereby grants the Company access to the area where the advanced meter set and related equipment are to be installed for purposes of installation, maintenance and removal of same. The Customer agrees, not to attempt or permit a third party to attempt, to adjust, modify or remove the advanced meter set without the prior written approval of the Company. Upon termination of the Agreement, the Company will remove the advanced meter set and associated equipment.

8. Miscellaneous. This Agreement constitutes the entire agreement between the parties regarding the subject matter hereof, and supersedes any prior or contemporaneous statements regarding the same. No modification of this Agreement shall be binding unless it is in writing and accepted by the Customer and the Company. This Agreement shall be governed by the laws of the State of Florida.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by their duly authorized representatives, as of the Effective Date hereof.

CUSTOMER____________________	TAMPA ELECTRIC COMPANY
By: ____________________	By: ____________________
Title: ____________________	Title: ____________________

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

Item 14

FILED NOV 18, 2015
DOCUMENT NO. 07320-15
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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Rome, Guffey) CRR SKG PD ED GB
Office of the General Counsel (Harper) AH SMC.

RE: Docket No. 150222-EU – Petition for variance from or waiver of Rule 25-6.049(5) and (6), F.A.C., by 4111 South Ocean Drive, LLC.

AGENDA: 12/03/15 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brown

CRITICAL DATES: Commission must grant or deny the petition by January 11, 2016, pursuant to Section 120.542(8), F.S.

SPECIAL INSTRUCTIONS: None

Case Background

4111 South Ocean Drive, LLC, Inc. (the "Developer"), the developer of the condominiums located at 4111 South Ocean Drive, Hollywood, Florida 33019 ("4111"), requests a waiver of the requirements of Rule 25-6.049(5) and (6), Florida Administrative Code (F.A.C.). The rule sets forth the conditions under which individual occupancy units in residential and commercial buildings must be metered for their electricity use. The rule requires that all occupancy units at 4111 must be individually metered by the utility unless 4111 meets one of the exemptions set forth in paragraphs (a) through (g) of the rule. The Developer seeks a waiver from this requirement for 4111. If granted, the rule waiver would allow the installation of a single master meter to measure usage for all of the residential units at 4111. The waiver is sought because the Developer contends that 4111 will operate in a manner similar to hotels and motels, which, under paragraph (d) of the rule, are not required to be individually metered. The Commission designated Mr. Marc Mazo as a qualified representative to represent the interests of the Developer in this docket by Order No. PSC-15-0352-FOF-OT, issued September 1, 2015.

Notice of the petition was published in the Florida Administrative Weekly on October 14, 2015. The comment period expired on October 28, 2015, and no comments were received.

This recommendation addresses whether the Commission should grant the petition for rule waiver. The Commission has jurisdiction pursuant to Sections 366.05, and 366.81, 366.82, Florida Statutes (F.S.), and Section 120.542, F.S.

Discussion of Issues

Issue 1: Should the Commission grant the Developer's request for waiver of the requirements of Rule 25-6.049(5) and (6), F.A.C.?

Recommendation: Yes. The petitioner has demonstrated that the purpose of the underlying statutes will be achieved by other means and that application of the rule would both create a substantial hardship and violate principles of fairness for 4111. The petitioner should be put on notice that as a master meter customer: 1) 4111 must allocate the cost of electricity to the individual 4111 unit owners using a reasonable apportionment method, consistent with Rule 25-6.049(9)(a), F.A.C.; 2) 4111 will be responsible for all of the costs associated with the conversion from individual metering to master metering, consistent with Rule 25-6.049(7), F.A.C.; and 3) The waiver will be effective for only so long as all or substantially all of the units are operated on a transient basis and 4111 is operated and licensed as a transient occupancy facility. At such time 4111 is no longer so operated and licensed, 4111 must inform FPL within 10 days and request FPL to install individual meters on all the occupancy units. In the event such a conversion to individual metering is required, 4111 will be solely responsible for the cost of such conversion, consistent with Rule 25-6.049(7), F.A.C. (Rome, Guffey, Harper)

Staff Analysis: The petitioner, the Developer, is the operator of 4111 South Ocean Drive, Hollywood, Florida, which is located in Florida Power & Light Company's (FPL) service area. The Developer states 4111 is under construction and that before or upon its completion, 4111 will be named Hyde Resort and Residences and will register and be licensed as a hotel and resort as defined in Section 509.242(a), F.S. Upon receiving its registration and license by the Florida Department of Business and Professional Regulation to engage in the business of transient lodging, 4111 will register with the Florida Department of Revenue to collect and remit sales taxes on revenue realized from providing such transient accommodations. 4111 will be in direct competition with hotels, motels, and resorts in the area.

The Developer states that 4111 will consist of 367 "resort" units, which are restricted by the City of Hollywood to stays of no more than 150 days in any consecutive 12 month period by the same occupant. No permanent residency will be allowed in the 367 resort units. Additionally, there will be 40 traditional condominium units, which will be sold with the intent to operate as a part of the hotel. There will also be 3 commercial units, which could potentially be a restaurant, café, or bakery. 4111 seeks waiver of Rule 25-6.049(5), F.A.C., because only 90 percent, not 95 percent, of the units will be used solely for overnight occupancy. 4111 meets the other criteria in Rule 25-6.049(5)(g), F.A.C.

4111 will be managed by Gemstone Hotel and Resorts (Gemstone), which is a full service hotel management company specializing in luxury, urban hotels and resorts. Gemstone will manage the rentals of 4111 units on a daily and weekly basis to the traveling public, similar to hotels, motels, and resorts throughout Florida. Gemstone will provide management personnel for the resort, including a General Manager, Assistant Manager, Front Desk Manager and Night Manager to oversee sales and marketing, guest services, accounting, security and the general safety and wellbeing of guests.

In addition, Gemstone will provide certain hotel-type services to all 4111 units which include but are not limited to: concierge services, day porter services, housekeeping, linen services, marketing and advertising, laundry and dry cleaning, transportation, and business service center. Gemstone will also maintain a lobby, front desk in the lobby area for guest registration and check-out, and a central telephone switchboard. Gemstone will assist with advertising and utilize a nationally known reservation software program to help keep the units at 4111 occupied.
Rule 25-6.049(5), F.A.C., requires utilities to individually meter each separate 4111 unit. The Developer seeks a waiver that would allow 4111 to be billed under a master meter that would serve all of 4111's units instead of an individual meter on each unit. This would allow the residential units to be billed under a single commercial account, instead of separate residential accounts. These consolidations will likely result in lower electricity costs to 4111. Projected annual savings are approximately $111,129 per year.

Requirements of Section 120.542, F.S.

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

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

(Emphasis added).

Purpose of the Underlying Statutes

Pursuant to section 120.542, F.S., the petitioner must demonstrate that the purpose of the underlying statute will be or has been achieved by other means by the person. Rule 25-6.049, F.A.C., implements section 366.05(1), F.S., and sections 366.81 and 366.82, F.S. Section 366.05(1), F.S., gives the Commission the authority to prescribe rate classifications and service rules and regulations to be observed by investor-owned electric utilities. Rule 25-6.049(5), F.A.C., implements this statute by setting forth the circumstances under which individual occupancy must be metered by the utility. Sections 366.81 and 366.82, F.S., are known collectively as the Florida Energy Efficiency and Conservation Act, or FEECA. This statute directs the Commission to adopt goals and approve plans related to the conservation of electric energy. Rule 25-6.049(5), F.A.C., implements this statute by setting forth the conditions under which individual occupancy units must be metered by the utility. The requirement that individual occupancy units be individually metered serves the conservation goals of FEECA because when unit owners are responsible for paying based on their actual electricity consumption, they are more likely to conserve to minimize their bills.

Rule 25-6.049(5), F.A.C., provides certain exemptions from the individual metering requirement for facilities for which it is not practical to attribute usage to individual occupants due to their nature or mode of operation. For example, hotels and motels are commercial enterprises in which the occupants of the units are not billed for their use of electricity, but pay a bundled rate for the use of a room for a limited time. The rule also exempts timeshare plans from the individual metering requirement, because the owners purchase the right to use a unit for a specified period of time, typically one week. Timeshare owners do not directly pay for the electricity used during their stay. Instead, the cost of electricity is apportioned based on ownership interest. Similarly, residents of nursing homes and similar care facilities also typically are not billed for their individual use of electricity, but pay a bundled price. In each exemption, there is little or no conservation incentive gained by requiring individual metering because the occupants of the units do not pay directly for the electricity they use. Thus, conservation efforts in such cases are more effectively carried out by the building manager, who can implement measures to reduce the overall electricity consumption of the facility.

Rule 25-6.049(5)(d), F.A.C., provides individual electric meters shall not be required for lodging establishments such as hotels, motels, and similar facilities which are rented, leased, or otherwise provided to guests by an operator providing overnight occupancy as defined in paragraph (8)(b) of the rule. Rule 25-6.049(8)(b), F.A.C., states overnight ccupancy means use of an occupancy unit for a short term such as per day or per week where permanent residency is not established.

Based on the representations of the Developer, staff believes the exemption provided by Rule 25-6.049(5)(d), F.A.C., is applicable to 4111's units because 4111 will be operated in a manner similar to that of hotels, motels, and resorts, with no permanent residency. Moreover, 4111 meets the criteria in Rule 25-6.049(5)(g), F.A.C., which includes maintaining a registration desk, lobby and central telephone switchboard and recording the names of inidivudual occupying the units between each check-in and check-out date. Additionally, staff believes that the purpose of FEECA will be fulfilled and, because of the nature of the operation of 4111, conservation efforts will be effectively carried out by the General Manager, Assistant Manager, Chief Engineer, and Director of Housekeeping.

Rule 25-6.049(9)(a), F.A.C., states that if master metering is used, the cost of electricity may be allocated to the individual occupancy units using "reasonable apportionment methods." Consistent with this rule, the Developer states that if the waiver is granted, the cost of electricity to 4111 will be recovered from the unit owners through a pro rata apportionment based on the square footage of the unit as compared to the total square footage of all units. Staff believes that this apportionment method is reasonable and fulfills the purpose of Section 366.05(1), F.S.

Substantial Hardship and Principles of Fairness

Pursuant to Section 120.542, F.S., the petitioner must also demonstrate that application of the rule would create a substantial hardship or would violate principles of fairness. Substantial hardship is defined as a demonstrated economic, technologic, legal or other type of hardship to the person requesting the waiver. Principles of fairness are violated when the literal application of a rule affects a particular person in a manner significantly different from the way it affects other similarly situated persons who are subject to the rule. As discussed below, staff believes that the Developer has demonstrated that application of the rule creates a substantial hardship and violates principles of fairness.

The Developer asserts that application of the rule will create a substantial hardship because it will place 4111 at a competitive disadvantage with respect to the motels and hotels with which it competes for guests. Because motels and hotels are exempt from the individual metering requirement under paragraph (5)(d) of the rule, they benefit from the lower electricity costs of master metering. 4111 estimates that without being allowed to master meter, 4111 will pay more for the same electric service to operate its transient rental business than other hotels, motels, and similarly situated resorts that have been master metered. Staff believes that the application of the rule in this instance will result in substantial economic hardship.

The Developer asserts that the application of the rule in this particular instance results in different treatment to similarly situated facilities. The Developer contends that 4111 will be operated in a manner similar to that of hotels and motels, which are exempt from the individual metering requirement under paragraph (5)(d) of the rule. Thus, staff believes that the disparate treatment of similar facilities that results from the application of the rule constitutes a violation of the principles of fairness as defined in Section 120.542(2), F.S.

Conclusion

Based upon the foregoing, staff recommends that the request for waiver of Rule 25-6.049(5) and (6), F.A.C., be granted. Staff believes that the petitioner has demonstrated that the purpose of the underlying statutes will be achieved by other means and that application of the rule would both create a substantial hardship and violate principles of fairness for 4111. The petitioner should be put on notice that as a master meter customer:

1) 4111 must allocate the cost of electricity to the individual 4111 unit owners using a reasonable apportionment method, consistent with Rule 25-6.049(9)(a), F.A.C.;

2) 4111 will be responsible for all of the costs associated with the conversion from individual metering to master metering, consistent with Rule 25-6.049(7), F.A.C.; and

3) The waiver will be effective for only so long as all or substantially all of the units are operated on a transient basis and 4111 is operated and licensed as a transient occupancy facility. At such time that 4111 is no longer so operated and licensed, 4111 must inform FPL within 10 days and request FPL to install individual meters on all the occupancy units. In the event such a conversion to individual metering is required, 4111 will be solely responsible for the cost of such conversion, consistent with Rule 25-6.049(7), F.A.C.

The recommendation is similar to Commission Orders PSC-05-0258-PAA-EU,[1] PSC-04-0861-PAA-EU,[2] and PSC-13-0579-PAA-EU.[3] Those dockets addressed waivers of the individual metering requirement for similar hotel/condominium facilities.

[1] Issued March 8, 2005, in Docket No. 050010-EU, In Re: Petition for variance from or waiver of metering requirement of Rule 25-6.049(5)(a), F.A.C., by Beach House Owners Association, Inc.
[2] Issued September 3, 2004, in Docket No. 040525-EU, In Re: Petition for variance from or waiver of metering requirement of Rule 25-6.049(5)(a), F.A.C., by Jetty East Condominium Association, Inc.
[3] Issued October 21, 2013, in Docket No. 130224-EU, In Re: Petition for variance from or waiver of metering requirement of Rule 25-6.049(5)(a), F.A.C., by Hallandale Beach, LLC.

Issue 2: Should this docket be closed?

Recommendation: Yes, 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, this docket should be closed upon the issuance of a consummating order. (Harper)

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, this docket should be closed upon the issuance of a consummating order.

Item 15

FILED NOV 18, 2015
DOCUMENT NO. 07299-15
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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Guffey, Draper) SKG EJD PD
Office of the General Counsel (Janjic) DJ JSC

RE: Docket No. 150191-GU – Joint petition for approval to implement gas reliability infrastructure program (GRIP) for Florida Public Utilities Company-Fort Meade and for approval of GRIP cost recovery factors by Florida Public Utilities Company, Florida Public Utilities Company-Fort Meade and the Florida Division of Chesapeake Utilities Corporation.

AGENDA: 12/03/15 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 8-Month Effective Date: 05/01/16 (60-day suspension date waived by the utility)

SPECIAL INSTRUCTIONS: None

Case Background

On September 1, 2015, Florida Public Utilities Company (FPUC), FPUC-Fort Meade (Fort Meade), and the Florida Division of Chesapeake Utilities Corporation (Chesapeake), collectively the Company, filed a petition seeking approval to implement a new gas reliability infrastructure program (GRIP) for Fort Meade and for approval of GRIP cost recovery factors for FPUC, Fort Meade, and Chesapeake.

The GRIP program for FPUC and Chesapeake was originally approved in Order No. PSC-12-0490-TRF-GU[1] (2012 order) to recover the cost of accelerating the replacement of cast iron and bare steel distribution mains and services through a surcharge on customers' bills. FPUC and Chesapeake's currently effective surcharges were approved in Order No. PSC-14-0693-TRF-GU.[2] FPUC's and Chesapeake's proposed 2016 GRIP surcharges are discussed in Issue 1 of the recommendation.

Fort Meade currently does not have a GRIP program and is requesting Commission approval to implement a GRIP program in the instant petition. On October 27, 2015, the Company filed an amended petition for approval to implement GRIP for Fort Meade. Fort Meade's proposed implementation of a GRIP program is discussed in Issue 2 of the recommendation.

The 2012 order for FPUC and Chesapeake addressed the reliability and safety rationale for pipeline replacement, the scope of the program, similar actions in other states, and the procedure for annually setting the GRIP surcharge to recover the costs of the program. The procedure requires an annual filing with three components:

1. A final true-up showing the actual replacement costs, actual surcharge revenues, and over- or under-recovery amount for the 12-month historical period from January 1 through December 31 of the year prior to FPUC's/Chesapeake's annual GRIP petition.

2. An actual/estimated true-up showing seven months of actual and five months of projected replacement costs, surcharge revenues, and over- or under-recovery amount.

3. A revenue requirement projection showing 12 months of projected GRIP revenue requirement for the period beginning January 1 following FPUC's/Chesapeake/s annual GRIP petition filing.

The Commission concluded the 2012 order by stating:

> Replacement of bare steel pipelines is in the public interest to improve the safety of Florida's natural gas infrastructure, thereby reducing the risk to life and property. Given the length of time these pipelines have been installed and the leak history due to corrosion, we find that it is appropriate to approve the proposed replacement program. Without the GRIP surcharge, it is reasonable to expect that FPUC/Chesapeake will have to file for more frequent base rate proceedings to recover the expenses of an accelerated replacement program. The annual filings will provide us with the oversight to ensure that projected expenses are trued-up and only actual costs are recovered. FPUC's/Chesapeake's GRIP

[1] Order No. PSC-12-0490-TRF-GU, issued September 24, 2012, in Docket No. 120036-GU, *In re: Joint petition for approval of Gas Reliability Infrastructure Program (GRIP) by Florida Public Utilities Company and the Florida Division of Chesapeake Utilities Corporation.*

[2] Order No. PSC-14-0693-TRF-GU, issued December 15, 2014, in Docket No. 140166-GU, *In re: Joint petition for approval of Gas Reliability Infrastructure Program (GRIP) by Florida Public Utilities Company and the Florida Division of Chesapeake Utilities Corporation.*

> and its associated surcharges will terminate when all replacements have been made and the revenue requirement rolled into rate base.

On October 22, 2015, the Company filed responses to Staff's First Data Request. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes (F.S.).

Discussion of Issues

Issue 1: Should the Commission approve FPUC's and Chesapeake's proposed GRIP surcharge factors for 2016?

Recommendation: Yes. The Commission should approve FPUC's and Chesapeake's proposed GRIP surcharges for each rate class commencing with bills rendered for meter readings taken on or after January 1, 2016. (Guffey, Draper)

Staff Analysis: The FPUC and Chesapeake surcharges have been in effect since January 2013. FPUC and Chesapeake state that they continue to replace eligible infrastructure aggressively. Both companies prioritize the potential replacement projects in areas of high consequence and areas susceptible to corrosion. These areas are dictated by the Distribution Integrity Management Program, which uses a risk-based prioritization designed to determine the replacement order for cast iron and bare steel pipelines. Attachment 1 provides an update of mains and services replaced and the replacement forecast through the end of the term of the GRIP program in 2022 for FPUC and Chesapeake. The companies appear to be on track to complete the replacements on time.

FPUC's True-ups by Year

FPUC's calculations for the 2016 GRIP revenue requirement and surcharges include a final true-up for 2014, an actual/estimated true-up for 2015, and projected costs for 2016. Attachment 2 contains tables showing the calculation for each year. Staff notes that FPUC recovers $747,727 of annual GRIP expenses in base rates. The amount included in base rates is excluded from the GRIP surcharge calculation.

Final True-up for 2014

FPUC stated that the GRIP revenues for 2014 were $674,601, compared to a revenue requirement of $2,381,424. The resulting under-recovery is $1,706,823. After adding interest of $139 and the end of 2013 over-recovery ($414,542), the final 2014 true-up is an under-recovery of $1,292,420.

Actual/Estimated 2015 True-Up

FPUC provided actual GRIP revenues for January through July and estimated revenues for August through December, which total $4,283,483. The actual/estimated revenue requirement for 2015 is $5,770,685 and includes a return on investment, depreciation expense, and property tax expense. The forecast under-recovery for 2015 is $1,487,202. After adding interest of $1,388, and the final 2014 under-recovery of $1,292,420, the total 2015 under-recovery is $2,781,010.

Projected 2016 Costs

FPUC projects capital expenditures of $12,237,715 for the replacement of cast iron/bare steel infrastructure in 2016. This compares with final 2014 expenditures of $19,128,274 and actual/estimated 2015 expenditures of $25,207,005. The return on investment, net depreciation expense, customer notification, and property tax expenses associated with that investment are $8,920,386. Subtracting the revenue requirement for bare steel replacement investment included in base rates results in a 2016 revenue requirement of $8,172,659. After adding the total 2015 under-recovery of $2,781,010, the 2016 revenue requirement is $10,953,669.

Chesapeake's True-ups by Year

Chesapeake does not have a replacement recovery amount embedded in base rates. Chesapeake's calculations for the 2016 GRIP revenue requirement and surcharges include a final true-up for 2014, an actual/estimated true-up for 2015, and projected costs for 2016. Attachment 3 contains tables showing the calculation for each year.

Final True-Up for 2014

Chesapeake's stated that the GRIP revenues for 2014 were $666,121, compared to total replacement costs of $967,391. The resulting under-recovery is $301,270. After adding interest of $12 and the end of 2013 over-recovery amount ($90,107), the final 2014 under-recovery is $211,175.

Actual/Estimated 2015 True-Up

Chesapeake provided actual GRIP revenues for January through July and forecast revenues for August through December, which total $1,800,824. The actual/estimated GRIP revenue requirement for 2015 is $1,717,692 and includes a return on investment, depreciation expense, and property tax expense. The forecast over-recovery for 2015 is $83,132. After adding interest of $81 and the 2014 over-recovery amount ($211,175), the total 2015 under-recovery is $127,962.

Projected 2016 Costs

Chesapeake projects capital expenditures of $4,447,860 for the replacement of cast iron/bare steel infrastructure in 2016. This compares with final 2014 expenditures of $5,196,099 and actual/estimated 2015 expenditures of 5,815,969. The return on investment, depreciation expense, and property tax expense to be recovered in 2016 totals $2,432,850. After adding the total 2015 under-recovery of $127,962, the total 2016 revenue requirement is $2,560,812.

Proposed Surcharges for FPUC and Chesapeake

As established in the 2012 order approving the GRIP, the total 2016 revenue requirement is allocated to the rate classes using the same methodology that was used for the allocation of mains and services in the cost of service study used in the companies' most recent rate case. After calculating the percentage of total plant costs attributed to each rate class, the respective percentages were multiplied by the 2016 revenue requirement, resulting in the revenue requirement by rate class. Dividing each rate class' revenue requirement by projected therm sales provides the GRIP surcharge for each rate class.

The proposed 2016 GRIP surcharge for residential FPUC customers is $0.26393 per therm (compared to the current surcharge of $0.10516 per therm). The monthly bill impact is $5.50 beginning January 2016 for a residential customer who uses 20 therms per month. The proposed FPUC tariff page is provided in Attachment 4.

The proposed 2016 GRIP surcharge for residential Chesapeake customers on the FTS-1 rate is $0.08568 per therm (compared to the current surcharge of $0.05713 per therm). The monthly bill impact is $1.71 beginning January 2016 for a residential Chesapeake customer who uses 20 therms per month. The proposed tariff page is provided in Attachment 5.

Conclusion

Staff believes the calculation of the 2016 GRIP surcharge revenue requirement and the proposed GRIP surcharges for FPUC and Chesapeake are reasonable and accurate. Therefore, staff recommends approval of FPUC's and Chesapeake's proposed 2016 GRIP surcharge for each rate class commencing with bills rendered for meter readings taken on and after January 1, 2016.

Issue 2: Should the Commission approve the proposed GRIP program for Fort Meade?

Recommendation: Yes, the Commission should approve the proposed GRIP program for Fort Meade effective January 1, 2016. Fort Meade should file a petition to implement 2017 GRIP surcharges no later than September 1, 2016. (Guffey, Draper)

Staff Analysis: Fort Meade currently does not have a GRIP program. Fort Meade is located in Polk County and Fort Meade serves approximately 650 natural gas residential and commercial customers. FPUC and the City of Fort Meade executed a purchase agreement in 2013 for the sale of the City of Fort Meade's natural gas system and FPUC acquired the system in December 2013. The Commission approved Fort Meade's initial tariff sheets in Order No. PSC-13-0676-TRF-GU.[3] At that point Fort Meade started operating as a new investor-owned natural gas utility in Florida as a division of FPUC.

The Company explained that after the acquisition of the Fort Meade system, it found during a routine maintenance survey approximately 250 steel tubing services in the Fort Meade system. Steel services are subject to corrosion and are typically replaced with plastic services. In the petition filed on September 1, 2015, Fort Meade requested Commission approval to implement a GRIP program to replace the steel tubing services and associated GRIP surcharges effective January 2016 consistent with the purpose of the FPUC and Chesapeake GRIP programs the Commission approved in the 2012 order.

After filing the September 1, 2015 petition, the Company determined that the implementation of the GRIP surcharge for Fort Meade prior to October 2016 would be in violation of a term in the purchase agreement for the Fort Meade system. Therefore, the Company submitted an amended petition on October 27, 2015 as it relates to Fort Meade. Specifically, the amended petition requests that Fort Meade be allowed to implement a new GRIP program to be able to start the replacement of the Fort Meade steel services effective January 2016, however, defer collecting GRIP surcharges from customers until January 2017. If the Commission approves Fort Meade's proposed GRIP program in this issue, the Company anticipates making a GRIP filing in the fall of 2016 concurrent with the annual FPUC and Chesapeake GRIP filing, which will include actual/estimated replacement cost for 2016, projected replacement cost for 2017, and GRIP surcharges effective January 2017.

The Company states that using the same average replacement cost of services for FPUC and Chesapeake of $1,900 per service, the total projected investment for Fort Meade is $475,000 to replace 250 services. The Company anticipates if it acts aggressively that it will take approximately two years to replace the Fort Meade steel services. The estimated annual revenue requirement associated with half of the investment ($237,500) is $15,086. As with the approved FPUC and Chesapeake GRIP programs, the revenue requirement for Fort Meade includes depreciation expenses, return on investment, and property taxes. In response to staff's data request, the Company explained that it will notify the Fort Meade customers of the GRIP

[3] Order No. PSC-13-0676-TRF-GU, issued December 20, 2013, Docket No. 130258-GU, In re: *Petition for approval of tariff sheets reflecting gas service to customers in the City of Ft. Meade, by Florida Public Utilities Company.*

surcharge in December 2016 through a message on the customer's bill, separate mailing, and a message on the FPUC-Fort Meade website.

While the 2017 Fort Meade GRIP surcharge won't be determined until Fort Meade files a petition for a surcharge by September 1, 2017, Fort Meade currently estimates the 2017 residential GRIP surcharge to be $0.24155 per therm, or $4.83 for a customer who uses 20 therms per month. This estimated residential GRIP surcharge includes the revenue requirement for 2016 and 2017. If Fort Meade had implemented a surcharge in 2016, as contemplated in the petition filed September 1, 2016, based on only the 2016 projected revenue requirement, the surcharge would be $0.12065 per therm, or $2.41 for a customer who uses 20 therms per month. Delaying the implementation of the surcharge by a year therefore increases the surcharge to customers. However, staff notes that replacement cost may vary from current estimates and staff discussed with the Company to consider options such as spreading the recovery of the GRIP revenue requirement over two years to mitigate the initial impact on customers, if necessary. Staff believes that, as the Commission stated in the 2012 order, the replacement of bare steel pipelines is in the public interest and Fort Meade should start replacing the steel services in January 2016 and not delay implementation until January 2017.

Staff recommends that the Commission approve the proposed GRIP program for Fort Meade effective January 1, 2016. Fort Meade should file a petition to implement 2017 GRIP surcharges no later than September 1, 2016. Approval of a GRIP program for Fort Meade is consistent with the GRIP programs the Commission approved for FPUC, Chesapeake and Peoples Gas System.[4]

[4] Order No. PSC-12-0476-TRF-GU, issued September 18, 2012, in Docket No. 110320-GU, *In re: Petition for approval of Cast Iron/Bare Steel Pipe Replacement Rider (Rider CI/BSR), by Peoples Gas System.*

Issue 3: Should this docket be closed?

Recommendation: If Issues 1 and 2 are approved and 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. (Janjic)

Staff Analysis: If Issue 1 and 2 are approved and 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.

Table 1-1
FPUC Pipe Replacement Program Progress

Year	Main Replacements					Service Replacements	
	Replaced Cast Iron (miles)	Replaced Bare Steel (miles)	Remaining Cast Iron at Year End (miles)	Remaining Bare Steel at Year End (miles)	Total Miles Remaining	Replaced Number of Steel Services	Total Number of Remaining Steel Services
July 2012			0.9	197.10	198.00		7980
2012		6.00	0.9	191.10	192.00	91	7889
2013	0.6	26.40	0.3	164.70	165.00	2071	5818
2014		38.00	0.3	126.70	127.00	1275	4543
2015		41.00	0.3	85.70	86.00	905	3638
2016		20.00	0.3	65.70	66.00	815	2823
2017	0.3	13.70	0	52.00	52.00	595	2228
2018		14.00	0	38.00	38.00	595	1633
2019		14.00	0	24.00	24.00	595	1038
2020		14.00	0	10.00	10.00	595	443
2021		8.00	0	2.00	2.00	385	58
2022		2.00	0	0.00	0.00	58	0

Source: FPUC's response to staff's first data request

Table 1-2
Chesapeake Pipe Replacement Program Progress

Year	Main Replacements					Service Replacements	
	Replaced Cast Iron (miles)	Replaced Bare Steel (miles)	Remaining Cast Iron at Year End (miles)	Remaining Bare Steel at Year End (miles)	Total Miles Remaining	Replaced Number of Steel Services	Total Number of Remaining Steel Services
July 2012				152	152		762
2012		5	0	147	147	34	728
2013		3	0	144	144	139	589
2014		19	0	125	125	47	542
2015		40	0	85	85	280	262
2016		14	0	71	71	42	220
2017		14	0	57	57	42	178
2018		14	0	43	43	42	136
2019		14	0	29	29	42	94
2020		14	0	15	15	42	52
2021		12	0	3	3	40	12
2022		3	0	0	0	12	0

Source: Chesapeake's response to staff's first data request

Table 2-1
FPUC Final True-up for 2014

2014 GRIP Revenues	$674,601
2014 Net Revenue Requirement	$2,381,424
2014 Under-recovery	$1,706,823
Interest	$139
2013 Final True-up (over-recovery)	$414,542
2014 Final True-Up (under-recovery)	$1,292,420

Source: Schedule B-1 of the petition

Table 2-2
FPUC Actual/Estimated True-up for 2015

2015 GRIP Revenues	$4,283,483
2015 Net Revenue Requirement	$5,770,685
2015 Under-recovery	$1,487,202
Interest	$1,388
2014 Final True-up (under-recovery)	$1,292,420
2015 Total True-Up (under-recovery)	$2,781,010

Source: Schedule B-2 of the petition

Table 2-3
FPUC Projected 2016 Costs

2016 Projected Expenditures	$12,237,715
Return on Investment	$6,195,036
Depreciation Expense	$1,535,625
Tax and Customer Notice Expenses	$1,189,725
2016 Revenue Requirement	$8,920,386
Less Revenue Requirement in Base Rates	$747,727
2016 GRIP Revenue Requirement	$8,172,659
Plus Prior Period Under-Recovery	($2,781,010)
Total 2016 Revenue Requirement	$10,953,669

Source: Schedule C-1 of the petition

Table 3-1

Chesapeake Final True-up for 2014

2014 GRIP Revenues	$666,121
2014 Net Revenue Requirement	$967,391
2014 Under-recovery	$301,270
Interest	$12
2013 Final True-Up (over-recovery)	$90,107
2014 Final True-up (under-recovery)	$211,175

Source: Schedule B-1 of the petition

Table 3-2

Chesapeake Actual/Estimated True-up for 2015

2015 GRIP Revenues	$1,800,824
2015 Net Revenue Requirement	$1,717,692
2015 Over-Recovery	$83,132
Interest	$81
2014 Final True-Up (under-recovery)	$211,175
2015 Total True-Up (under-recovery)	$127,962

Source: Schedule B-2 of the petition

Table 3-3

Chesapeake Projected 2016 Costs

2016 Projected Expenditures	$4,447,860
Return on Investment	$1,669,415
Depreciation Expense	$427,963
Tax and Customer Notice Expenses	$335,472
2016 Revenue Requirement	$2,432,850
Plus Prior Period Under-recovery	$127,962
Total 2016 Revenue Requirement	$2,560,812

Source: Schedule C-1 of the petition

Florida Public Utilities Company
F.P.S.C. Gas Tariff
Third Revised Volume No. 1

Eleventh Revised Sheet No. 35.4
Cancels Tenth Revised Sheet No. 35.4

BILLING ADJUSTMENTS

(Continued from Sheet No. 35.3)

Gas Reliability Infrastructure Program (GRIP)

Applicability

The bill for gas or transportation service supplied to a Customer in any Billing Period shall be adjusted as follows:

The GRIP factors for the period from the first billing cycle for January 2016 through the last billing cycle for December 2016 are as follows:

Rate Class	Rates Per Therm
Rate Schedule RS	\$0.26393
Rate Schedule GS-1	\$0.18671
Rate Schedule GS-2	\$0.18671
Rate Schedule GSTS-1	\$0.18671
Rate Schedule GSTS-2	\$0.18671
Rate Schedule LVS	\$0.09700
Rate Schedule LVTS	\$0.09700
Rate Schedule IS	\$0.08621
Rate Schedule ITS	\$0.08621
Rate Schedule GLS	\$0.25625
Rate Schedule GLSTS	\$0.25625
Rate Schedule NGV	\$0.00000
Rate Schedule NGVTS	\$0.00000

(Continued to Sheet No. 35.5)

Issued by: Jeffry Householder, President

Effective:

RATE SCHEDULES
MONTHLY RATE ADJUSTMENTS
Rate Schedule MRA

7. GAS REPLACEMENT INFRASTRUCTURE PROGRAM (GRIP):

Applicability:

All Customers receiving Transportation Service from the Company and are assigned to or have selected rate schedules FTS-A, FTS-B, FTS-1, FTS-2, FTS-2.1, FTS-3, FTS-3.1, FTS-4, FTS-5, FTS-6, FTS-7, FTS-8, FTS-9, FTS-10, FTS-11, FTS-12, and FTS-1 3.

The Usage Rate for Transportation Service to each applicable rate classification shall be adjusted by the following recovery factors. The recovery factors for all meters read for the period January 1, 2016 through December 31, 2016 for each rate classification are as follows:

Rate Schedule	Classification of Service	Rate per therm
FTS A	< 130 therms	$0.32506
FTS-B	> 130 therms up to 250 therms	$0.12205
FTS-1	> 0 up to 500 therms	$0.08568
FTS-2	> 500 therms up to 1,000 therms	$0.08486
FTS-2.1	> 1,000 therms up to 2,500 therms	$0.08650
FTS-3	> 2,500 therms up to 5,000 therms	$0.03443
FTS-3.1	> 5,000 therms up to 10,000 therms	$0.05011
FTS-4	> 10,000 therms up to 25,000 therms	$0.05935
FTS-5	> 25,000 therms up to 50,000 therms	$0.05995
FTS-6	> 50,000 therms up to 100,000 therms	$0.04591
FTS-7	> 100,000 therms up to 200,000 therms	$0.06601
FTS-8	> 200,000 therms up to 400,000 therms	$0.04960
FTS-9	> 400,000 therms up to 700,000 therms	$0.07774
FTS-10	> 700,000 therms up to 1,000,000 therms	$0.06889
FTS-11	> 1,000,000 therms up to 2,500,000	$0.06947
FTS-12	> 2,500,000 therms up to 12,500,000	$0.02580
FTS-13	> 12,500,000 therms	N/A

(Continued to Sheet No. 105.2)

Issued by: Michael P. McMasters, President
Chesapeake Utilities Corporation

Effective:

Item 16

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Ollila) A.O.
Office of the General Counsel (Mapp)

RE: Docket No. 150203-GU – Petition for approval of 2014 true-up, projected 2015 true-up and 2016 revenue requirements and surcharges associated with cast iron/bare steel pipe replacement rider, by Peoples Gas System.

AGENDA: 12/03/15 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 8-Month Effective Date: 5/17/16 (60-Day Suspension Date Waived by the Utility)

SPECIAL INSTRUCTIONS: None

Case Background

On September 17, 2015, Peoples Gas System (Peoples or the Company) filed a petition for approval of its Cast Iron/Bare Steel Pipe Replacement Rider (Rider) program revenue requirements and surcharges for 2016, commencing with bills rendered for meter readings taken on and after January 1, 2016. The Rider was originally approved in Order No. PSC-12-0476-TRF-GU[1] (2012 order) to recover the cost of accelerating the replacement of cast iron and bare

[1] Order No. PSC-12-0476-TRF-GU, issued September 18, 2012, in Docket No. 110320-GU, *In re: Petition for approval of Cast Iron/Bare Steel Pipe Replacement Rider (Rider CI/BSR), by Peoples Gas System.*

steel distribution pipes through a surcharge on customers' bills. Peoples' current surcharges were approved in Order No. PSC-14-0682-TRF-GU.[2]

The 2012 order approving the Rider addressed the reliability and safety rationale for pipeline replacement, the scope of the program, similar actions in other states, and the procedure for annually setting the surcharge to recover the costs of the program. The procedure requires an annual filing with three components:

1. A final true-up showing the actual replacement costs and actual surcharge revenues for the most recent 12-month historical period from January 1 through December 31 that ends prior to the annual petition filing, including the final over- or under-recovery for the final true-up period.

2. An actual/estimated true-up showing seven months of actual and five months of projected costs and revenues.

3. A projection showing 12 months of projected Rider revenue requirement for the period beginning January 1 following the annual filing.

The Commission concluded the order by stating:

> We find that replacement of these types of pipelines is in the public interest to improve the safety of Florida's natural gas infrastructure, and reduce the possibility of loss of life and destruction of property should an incident occur. Given the length of time these pipelines have been installed and the leak history due to corrosion, it is appropriate to approve the proposed accelerated replacement program. Without the Rider, it is reasonable to expect that Peoples will have to file for more frequent base rate proceedings to recover the expenses of the program. The annual filings will provide us with the oversight to ensure that projected expenses are trued-up and only actual costs are recovered. The Rider and its associated surcharges will terminate when all replacements have been made and the revenue requirement has been rolled into rate base.[3]

In its petition, Peoples waived the 60-day file and suspend provisions of Section 366.06(3), Florida Statutes (F.S.). On October 20, 2015, Peoples filed responses to Staff's First Data Request. This recommendation addresses Peoples' 2014 final true-up, actual/estimated 2015 true-up, and 2016 revenue requirement and surcharges associated with its cast iron/bare steel pipe replacement rider. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, F.S.

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[2] Order No. PSC-14-0682-TRF-GU, issued December 9, 2014, in Docket No. 140183-GU, *In re: Petition for approval of Cast Iron/Bare Steel Pipe Replacement Rider (Rider CI/BSR), by Peoples Gas System.*

[3] Order No. PSC-12-0476-TRF-GU, issued September 18, 2012, in Docket No. 110320-GU, *In re: Petition for approval of Cast Iron/Bare Steel Pipe Replacement Rider (Rider CI/BSR), by Peoples Gas System).*

Discussion of Issues

Issue 1: Should the Commission approve Peoples' proposed Rider surcharges for 2016?

Recommendation: Yes. The Commission should approve Peoples' proposed 2016 Rider surcharge for each rate class commencing with bills rendered for meter readings taken on and after January 1, 2016. (Ollila)

Staff Analysis: The surcharges have been in effect since January 2013. Peoples' program continues to identify and target for replacement pipelines in the Company's more urban and high consequence areas. These areas are dictated by the Distribution Integrity Management Program, which uses a risk-based prioritization designed to determine the replacement order for cast iron and bare steel pipelines. Attachment 1 provides an update of mains and services replaced and the replacement forecast through the end of the term of the Rider in 2022. The Company appears to be on track to complete the replacements on time.

The 2012 order states that Peoples agreed to identify and report any operations and maintenance (O&M) and depreciation savings in its annual petition, beginning the second year. In this filing, Peoples reported depreciation expense savings for 2015 ($138,850) and 2016 ($60,000). Peoples stated that it has not been able to identify any O&M expense savings. Peoples indicated in its petition that it had a discussion with the Office of Public Counsel, and that once O&M savings can be identified and quantified, those savings will also be offset against expenses attributable to the cast iron and bare steel replacement program.

True-ups by year

Peoples' calculations for the 2016 revenue requirement and surcharges include a final true-up for 2014, an actual/estimated true-up for 2015, and projected costs for 2016. Attachment 2 contains tables showing the calculation for each year.

Final True-up for 2014

Peoples stated that the revenues for 2014 were $2,176,695, compared to a revenue requirement of $2,156,056. The resulting over-recovery is $20,640 (rounded). After adding interest of $159 and the final 2013 over-recovery of $33,685, and subtracting the 2013 over-recovery amount ($18,281) that was already collected in the 2014 surcharges, the final 2014 true-up is an over-recovery of $36,203.

Actual/estimated 2015 True-up

Peoples provided actual revenues for January through July and forecast revenues for August through December, which total $3,898,538. The actual/estimated revenue requirement for 2015 is $3,600,290 and includes a return on investment, depreciation expense (less savings), and property tax expense. The forecast over-recovery for 2015 is $298,247 (rounded). After adding interest of $353 and the final 2014 over-recovery of $36,203, and subtracting the 2014 over-recovery amount ($61,277) that was already collected in the 2015 surcharges, the total 2015 true-up is an over-recovery of $273,526.

Projected 2016 Costs

Peoples projects capital expenditures of $11,500,000 for the replacement of cast iron/bare steel infrastructure in 2016. This compares with final 2014 expenditures of $11,736,210 and actual/estimated 2015 expenditures of $12,110,859. The return on investment, depreciation expense (less savings), and property tax expense to be recovered in 2016 total $5,330,536. After subtracting the total 2015 over-recovery of $273,526, the 2016 revenue requirement is $5,057,010.

Proposed surcharges

As established in the 2012 order, the total 2016 revenue requirement is allocated to rate classes using the same methodology that was used for the allocation of mains and services in the cost of service study used in Peoples' most recent rate case. After calculating the percentage of total plant costs attributed to each rate class, the respective percentages were multiplied by the 2016 revenue requirement resulting in the revenue requirement by rate class. Dividing each rate class' revenue requirement by projected therm sales provides the Rider surcharge for each rate class.

The proposed 2016 Rider surcharge for residential customers is $0.02137 per therm (compared to the current surcharge of $0.01876 per therm). The monthly bill impact is $0.43 beginning January 1, 2016 for a residential customer who uses 20 therms. The proposed tariff page is provided in Attachment 3.

Conclusion

Staff believes the calculation of the 2016 Rider revenue requirement and the proposed Rider surcharge for each rate class is reasonable and accurate. Therefore, staff recommends approval of Peoples' proposed 2016 Rider surcharge for each rate class commencing with bills rendered for meter readings taken on and after January 1, 2016.

Issue 2: Should this docket be closed?

Recommendation: If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff 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. (Mapp)

Staff Analysis: If Issue 1 is approved and a protest is filed within 21 days of the issuance of the order, the tariff 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.

Table 1-1
Peoples' Pipe Replacement Program Progress

Year	Main Replacements					Service Replacements	
	Replaced Cast Iron (miles)	Replaced Bare Steel (miles)	Remaining Cast Iron at Year End (miles)	Remaining Bare Steel at Year End (miles)	Total Miles Remaining	Replaced Number of Steel Services	Total Number of Remaining Steel Services
2012			100	354	454		14,978
2013	14	34	86	320	406	907	14,071
2014	4	42	82	278	360	950	13,121
*2015(projected)	13	48	69	230	299	3,521	9,600
2016	13	35	56	195	251	1,300	8,300
2017	13	35	43	160	203	1,300	7,000
2018	13	35	30	125	155	1,300	5,700
2019	13	35	17	90	107	1,300	4,400
2020	13	35	4	55	59	1,300	3,100
2021	4	35	0	20	20	1,300	1,800
2022	0	20	0	0	0	1,800	0

Source: Peoples' response to staff's data request

Table 2-1
Final True-up for 2014

2014 Revenues	$2,176,695
2014 Revenue Requirement	$2,156,056
2014 Over-recovery (rounded)	$20,640
Interest	$159
2013 Final True-up (over-recovery)	$33,685
Less 2013 True-up Refunded	($18,281)
2014 Final True-up (over-recovery)	$36,203

Source: Exhibit A of the petition

Table 2-2
Actual/Estimated True-up for 2015

2015 Revenues	$3,898,538
2015 Revenue Requirement	$3,600,290
2015 Over-recovery (rounded)	$298,247
Interest	$353
2014 Final True-up (over-recovery)	$36,203
Less 2014 True-up Refunded	($61,277)
2015 Total True-up (over-recovery)	$273,526

Source: Exhibit B of the petition

Table 2-3
Projected 2016 Costs

2016 Projected Replacements	$11,500,000
Return on Investment	$3,612,427
Depreciation Expense (less savings)	$1,141,189
Property Tax Expense	$576,920
2016 Revenue Requirement	$5,330,536
Less 2015 Total True-up	($273,526)
Total 2016 Revenue Requirement	$5,057,010

Source: Exhibit C of the petition

Peoples Gas System
a Division of Tampa Electric Company
Original Volume No. 3

Third Revised Sheet No. 7.806
Cancels Second Sheet No. 7.806

CAST IRON/BARE STEEL REPLACEMENT RIDER
RIDER CI/BSR

The monthly bill for Gas Service in any Billing Period shall be increased by the CI/BSR Surcharge determined in accordance with this Rider. CI/BSR Surcharges approved by the Commission for bills rendered for meter readings taken on or after January 1, 2016, are as follows with respect to Customers receiving Gas Service under the following rate schedules:

Rate Schedule	CI/BSR Surcharge
Residential/Residential Standby Generator	$0.02137 per therm
Small General Service	$0.01647 per therm
General Service – 1/ Commercial Standby Generator Service	$0.00991 per therm
General Service – 2	$0.00891 per therm
General Service – 3	$0.00717 per therm
General Service – 4	$0.00507 per therm
General Service – 5	$0.00241 per therm
Commercial Street Lighting	$0.01116 per therm
Natural Gas Vehicle Service	$0.02223 per therm
Wholesale	$0.00313 per therm

The CI/BSR Surcharges set forth above shall remain in effect until changed pursuant to an order of the Commission.

CI/BSR Surcharges shall be determined in accordance with the provisions of this Rider set forth below.

Definitions

For purposes of this Rider:

"Eligible Replacements" means the following Company plant investments that (i) do not increase revenues by directly connecting new customers to the plant asset, (ii) are in service and used and useful in providing utility service and (iii) were not included in the Company's rate base for purposes of determining the Company's base rates in its most recent general base rate proceeding:

Mains and service lines, as replacements for existing cast iron, wrought iron and bare steel facilities, and regulators and other pipeline system components the installation of which is required as a consequence of the replacement of the aforesaid facilities.

"CI/BSR Revenues" means the revenues produced through CI/BSR Surcharges, exclusive of revenues from all other rates and charges.

Issued By: G. L. Gillette, President

Effective: January 1, 2016

Item 17

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Rome, Draper) CRR EJD P.D.
Office of the General Counsel (Villafrate) JSC

RE: Docket No. 150221-GU – Petition for approval of firm service agreement with Peoples Gas System for an extension in Clay County, by SeaCoast Gas Transmission, L.L.C.

AGENDA: 12/03/15 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: Please place this item immediately prior to the item for Docket No. 150220-GU on the Agenda

Case Background

On October 13, 2015, SeaCoast Gas Transmission, L.L.C. (SeaCoast) filed a petition seeking approval of a firm transportation service agreement (Agreement) between SeaCoast and Peoples Gas System (Peoples). Pursuant to the Agreement, SeaCoast will transport natural gas to Peoples' distribution system on a firm basis. SeaCoast operates as a natural gas transmission company as defined in Section 368.103(4), Florida Statutes (F.S.). Peoples is a natural gas distribution company serving retail customers throughout Florida and is subject to the Commission's jurisdiction under Chapter 366, F.S.

In Order No. PSC-08-0747-TRF-GP, SeaCoast received approval of an intrastate gas pipeline tariff that allows it to construct and operate intrastate pipeline facilities and to actively pursue agreements with gas customers.[1] SeaCoast provides transportation service only and does not engage in the sale of natural gas. Pursuant to Order No. PSC-08-0747-TRF-GP, SeaCoast is allowed to enter into certain gas transmission agreements without prior Commission approval. However, SeaCoast is requesting approval of this agreement as it does not fit any of the criteria enumerated in the tariff for which Commission approval would not be required.[2] SeaCoast and Peoples are affiliates in that their parent company is TECO Energy, Inc. Agreements between affiliated companies must be approved by the Commission pursuant to Section 368.105, F.S., and Order No. PSC-08-0747-TRF-GP.

SeaCoast plans to construct and operate an approximately 9.5-mile, 6-inch coated steel transmission pipeline in Clay County, Florida and is seeking Commission approval of a firm transportation service agreement with Peoples. Peoples will then interconnect with the new SeaCoast transmission pipeline and expand its distribution system to serve new load in Green Cove Springs and surrounding areas of Clay County where natural gas service is not currently available. The route of the proposed SeaCoast pipeline is shown in Attachment A.

On October 20, 2015, the Office of Public Counsel (OPC) filed a notice of intervention in the docket and on October 21, 2015, Peoples, OPC and staff met in a noticed meeting. During its evaluation of the petition, staff issued a data request to both SeaCoast and Peoples for which responses were received on October 26, 2015. The Commission has jurisdiction over this matter pursuant to Sections 366.06 and 368.105, F.S.

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[1] Order No. PSC-08-0747-TRF-GP, issued November 12, 2008, in Docket No. 080561-GP, *In re: Petition for approval of natural gas transmission pipeline tariff by SeaCoast Gas Transmission, LLC.*

[2] SeaCoast Gas Transmission, LLC, Intrastate Pipeline Tariff, Original Volume 1, Sheet No. 2.

Discussion of Issues

Issue 1: Should the Commission approve the Agreement between SeaCoast and Peoples dated October 7, 2015?

Recommendation: Yes. The Commission should approve the Agreement dated October 7, 2015, for SeaCoast to provide firm transportation service to Peoples. (Rome, Draper)

Staff Analysis: To provide intrastate transportation of gas to Peoples, SeaCoast will tap into its existing 24-inch transmission pipeline near Asbury Lake and construct an approximately 9.5-mile 6-inch coated steel transmission pipeline to interconnect with a new Peoples distribution main in the vicinity of Green Cove Springs. In addition to the distribution main, Peoples will construct service lines for the purpose of delivering gas to customers in and around Green Cove Springs. Seacoast's existing 24-inch transmission pipeline interconnects with Southern Natural Gas Company (SNG), an interstate pipeline company, in northwest Clay County.

SeaCoast and Peoples stated that the preliminary design for the infrastructure extensions has been completed and the negotiation of a franchise agreement with the City of Green Cove Springs has commenced. Pending Commission approval of the Agreement, the permitting process will be initiated and is expected to take from three to six months. Construction is anticipated to begin around the end of the first quarter or second quarter of 2016. SeaCoast and Peoples estimated that the SeaCoast transmission pipeline and the Peoples distribution main will be complete by the end of 2016.

The initial term of the proposed Agreement is 15 years, with an option to extend for an additional ten years. The negotiated reservation charge (confidential) included in the proposed Agreement is designed to allow SeaCoast to recover its operational and maintenance costs, depreciation, taxes, and return on investment associated with the new transmission pipeline. SeaCoast asserts that the rate set forth in the Agreement is a cost-based market rate similar to the rate set forth in the firm service agreement with its other customer, is just and reasonable, is not unreasonably preferential or unduly discriminatory, and is therefore consistent with Section 368.105(3)(b), F.S. While specific circumstances vary for different projects due to pipe size, construction conditions, permitting, etc., staff believes that the information provided by SeaCoast for the proposed pipeline appears reasonable and comparable to similar agreements.[3]

Consideration of Potential Alternatives to the SeaCoast Extension

Peoples stated that it evaluated other options to deliver gas to customers in the Green Cove Springs area, but those alternatives had shortcomings. One of the options considered was Peoples constructing a transmission pipeline that would have interconnected with Florida Gas

[3] See Order No. PSC-15-0206-PAA-GU, issued May 26, 2015, in Docket No. 150031-GU, *In re: Petition for approval of transportation service agreement with the Florida Division of Chesapeake Utilities Corporation by Peninsula Pipeline Company, Inc.*, Order No. PSC-14-0713-PAA-GU, issued December 31, 2014, in Docket No. 140189-GU, *In re: Petition for approval of transportation service agreement for an extension in Nassau County with Florida Public Utilities Company, by Peninsula Pipeline Company, Inc.*, and Order No. PSC-14-0712-PAA-GU, issued December 31, 2014, In Docket No. 140190-GU, *In re: Petition for approval of transportation service agreement for an extension in Palm Beach County with Florida Public Utilities Company, by Peninsula Pipeline Company, Inc.*

Transmission (FGT) in northwest Clay County. However, Peoples explained that capacity constraints on the FGT interstate pipeline would leave customers in Green Cove Springs vulnerable to interruptions and potential other difficulties in scheduling deliveries of gas at certain times. SeaCoast, on the other hand, provides Peoples with access to the SNG interstate pipeline system which currently has no capacity constraints.

In response to staff's data request, SeaCoast and Peoples provided a cost estimate for the proposed 6-inch SeaCoast transmission pipeline and stated that this alternative is the most cost effective. The proposed SeaCoast line utilizes existing pipeline infrastructure thereby eliminating duplication of facilities in the area and minimizing the impact on the environment and population in Clay County. Any other alternative would require approximately nine to ten additional miles of transmission line as well as additional taps and interconnects with FGT and SNG. These incremental costs would exceed the costs of the proposed SeaCoast alternative because the necessary SeaCoast taps with the interconnecting interstate pipelines are already in place.

Peoples also stated that it did not believe there are other companies capable of completing construction of the required interstate pipeline taps, interconnects, and the new pipeline from the interstate supply sources (*i.e.*, FGT and/or SNG) within the time frame in which the larger prospective Green Cove Springs customers desire natural gas service (mid-2016).

Peoples' Cost Recovery of Payments to SeaCoast

Peoples' payments to SeaCoast will be included in the calculation of the monthly Purchased Gas Adjustment (PGA) factor.[4] Consistent with the methodology approved by the Commission in Docket No. 000810-GU, a portion of the costs will be paid by transportation customers taking service under Peoples' Natural Choice Transportation Service program via the swing charge mechanism.[5] Swing service charge revenues collected from transportation customers will then be credited back to the PGA. The remaining balance of the swing service charge will remain embedded in Peoples' PGA and recovered from Peoples' sales customers. Sales customers purchase their gas from Peoples and are subject to Peoples' PGA charges.

In Docket No. 150220-GU, Peoples filed for Commission approval of tariff modifications related to the swing service charge. Peoples has included the reservation charges it would pay to SeaCoast under the proposed Agreement in this docket in the swing service charges proposed in Docket No. 150220-GU, which is also scheduled for the December 3, 2015 Agenda Conference.

Peoples anticipates that initially all of the approximately 60 new commercial customers in the Green Cove Springs area will receive transportation service under Peoples' Natural Choice Transportation Service program. Peoples further anticipates an increasing customer base throughout the term of the Agreement due to significant economic development activities in Clay County.

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[4] Peoples does not anticipate any impact on its 2016 PGA cap approved in Docket No. 150003-GU due to the de minimis nature of the SeaCoast charges when compared to Peoples' total projected 2016 PGA expenses.

[5] Order No. PSC-00-1814-TRF-GU, issued October 4, 2000, in Docket No. 000810-GU, *In re: Petition for approval of modifications to tariff provisions governing transportation of customer-owned gas and tariff provisions to implement Rule 25-7.0335, F.A.C., by Tampa Electric Company d/b/a Peoples Gas System.*

Conclusion

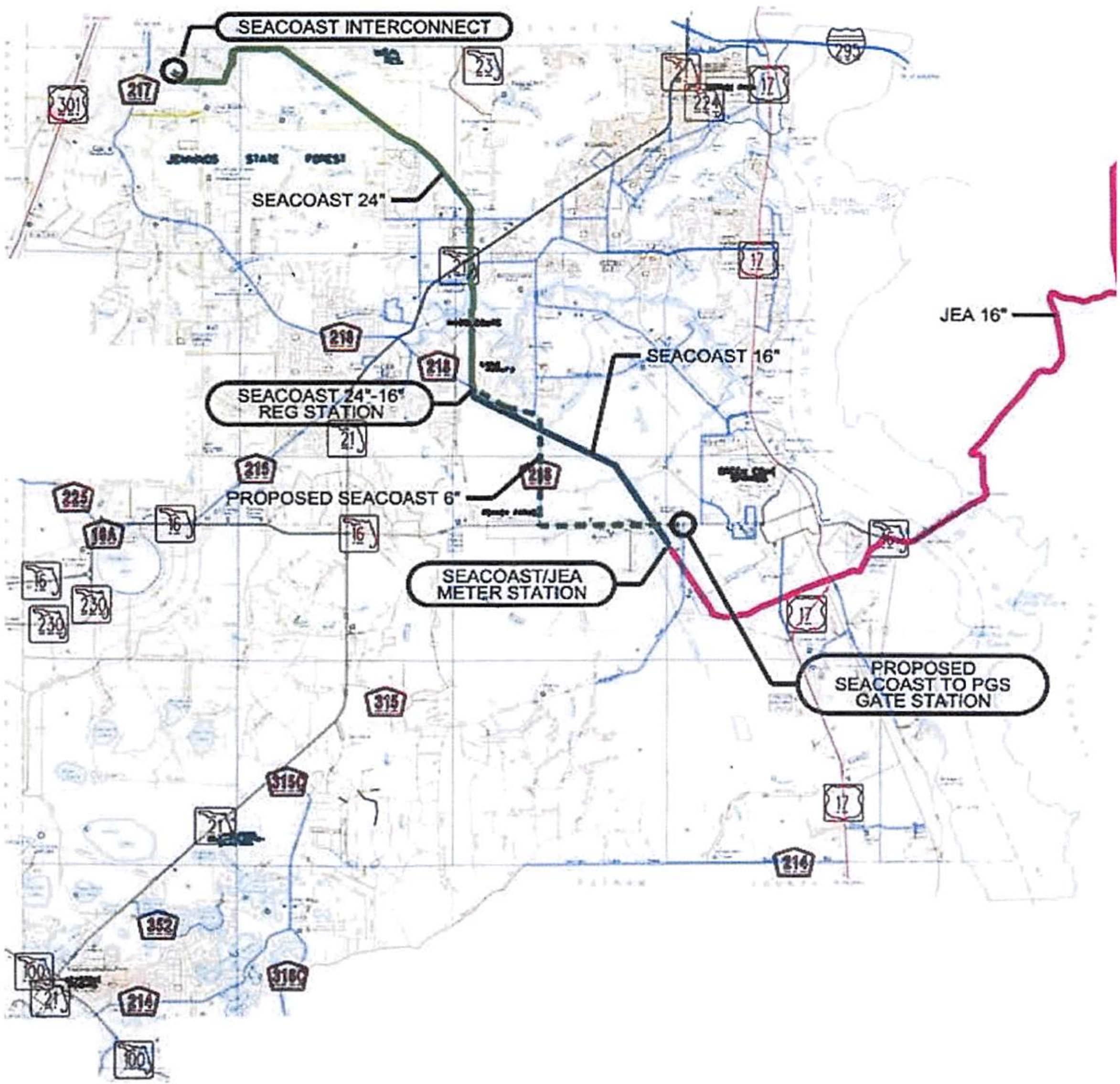
Based on the petition and responses from SeaCoast and Peoples to staff's data request, SeaCoast and Peoples have supported the importance of the need for the new pipeline to provide gas service to Green Cove Springs and the surrounding area. Staff believes that the proposed agreement is reasonable, meets the requirements of Section 368.105, F.S., and benefits Peoples' customers. Therefore, staff recommends approval of the Agreement dated October 7, 2015, for SeaCoast to provide firm transportation service to Peoples.

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. (Villafrate)

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.

Proposed SeaCoast Transmission Pipeline and Vicinity



Item 18

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Rome, Draper) CRC ED PD GB
Office of the General Counsel (Villafrate) JSC

RE: Docket No. 150220-GU – Petition for approval of tariff modifications related to the swing service charge, by Peoples Gas System.

AGENDA: 12/03/15 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 8-Month Effective Date: 6/9/2016 (60-day suspension date waived by the utility)

SPECIAL INSTRUCTIONS: Please place this item immediately following the item for Docket No. 150221-GU on the Agenda

Case Background

On October 9, 2015, Peoples Gas System (Peoples) filed a petition for approval of tariff modifications related to its swing service charge. The swing service charge is assessed to all customers who take service under Peoples' Natural Choice Transportation Service program called Rider NCTS.

The swing service charge was first approved in 2000 when Peoples filed numerous tariff changes to make transportation service available to all non-residential customers pursuant to Rule 25-7.0335, Florida Administrative Code (F.A.C.).[1] The proposed tariff changes are shown in

[1] Order No. PSC-00-1814-TRF-GU, issued October 4, 2000, in Docket No. 000810-GU, *In re: Petition for approval of modifications to tariff provisions governing transportation of customer-owned gas and tariff provisions to implement Rule 25-7.0335, F.A.C., by Tampa Electric Company d/b/a Peoples Gas System.*

Attachment A to the recommendation. The tariff page is in legislative format to display the proposed changes. In its petition, Peoples waived the 60-day file and suspend provisions of Section 366.06(3), Florida Statutes, (F.S.).

On October 12, 2015, the Office of Public Counsel (OPC) filed a notice of intervention in the docket and on October 21, 2015, Peoples, OPC and staff met in a noticed meeting. During its evaluation of the petition, staff issued a data request to Peoples for which a response was received on October 26, 2015. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.05, and 366.06, F.S.

Discussion of Issues

Issue 1: Should the Commission approve Peoples' tariff modifications related to the swing service charge?

Recommendation: Yes. The Commission should approve the tariff modifications related to the swing service charge to become effective as of the date of the Commission's vote. (Rome, Draper)

Staff Analysis: The swing service charge is assessed to all customers who choose to take transportation service under Rider NCTS. The Rider allows residential customers with an annual consumption of 2,000 or more therms and non-residential firm customers to use a third party supplier or pool manager to meet their natural gas requirements. The NCTS customer is part of a group of customers called a customer pool. The pool manager assumes the responsibility for supplying and managing the natural gas supply for a customer pool. Currently, NCTS customers can choose from 15 pool managers. Peoples receives gas delivered by the pool manager and redelivers the gas to the customer's site. Peoples introduced the NCTS program in 2000 and it has grown from 3,398 customers in October 2000 to 22,123 customers as of December 2014. Customers who buy their gas from Peoples are referred to as sales customers and are subject to Peoples' purchased gas adjustment (PGA) charges.

The pool managers deliver the monthly gas supply for their customer pool at a constant level every day even though customer usage varies. Therefore, the level of gas delivered daily differs from the quantity actually consumed by the customer pool. To offset this daily difference, Peoples varies ("swings") the level of gas and upstream pipeline capacity nominated for delivery to the Peoples system. Peoples is required to manage the customer swing for sales and NCTS customers with operational purchases or sales. The cost to manage the customer swing is included in the calculation of the PGA. A portion of the cost is paid by the NCTS customers via the swing service charge mechanism. The revenues derived from the swing service charge are credited to the PGA. The sales customers' share of the swing service costs remain embedded in the PGA.

Swing Service Charge Methodology

Peoples' methodology for determining the level of the swing service charge is consistent with the methodology approved in Commission Order No. PSC-00-1814-TRF-GU.[2] First, the swing service cost is estimated on a system-wide basis. Costs are estimated based on six primary tools used by Peoples to balance its system:

- Reserve capacity – interstate and intrastate pipeline capacity contracted to be available when customer usage increases.
- Swing gas supply – typically purchased on the spot market at varying levels of quantity and price.

[2] Id.

- No-notice transportation service – purchased from interstate pipelines at tariffed rates and allows system imbalances to be absorbed by the interstate pipeline.

- Storage contracts – scheduling of gas in or out of a storage facility (typically subterranean salt domes outside of Florida) to efficiently manage supply constraints, demand reductions, and price volatility.

- Swing sale agreements – agreements with large interruptible customers that have the ability to use alternative fuel to sell their gas supply to Peoples and switch to the customer's alternative fuel source.

- Park and loan services – an interruptible service which gives Peoples the flexibility of putting gas in an upstream pipeline's system for later use or borrowing gas from an upstream pipeline's system and paying back the volume at a later date.

Once the system-wide swing service cost has been determined, it is allocated among the rate classes according to the relative variation in monthly consumption for each rate class. Allocation among rate classes is based on the magnitude of the difference between each rate class's maximum monthly consumption and its minimum monthly consumption. Once allocated, the balancing cost assigned to each rate class is divided by the annual consumption of that class to yield the appropriate swing charge.

Proposed Swing Service Charge Modifications

Peoples proposed to update the swing service charges to reflect Peoples' current cost of providing swing service. Specifically, the proposed swing service charge revisions incorporate the following: (a) updated no-notice transportation service charges from Florida Gas Transmission Company, (b) updated costs associated with reserved upstream pipeline capacity that Peoples holds to ensure enough upstream capacity to meet customer demand during peak months, and (c) updated calculations of the swing service charge to include additional storage contracts, swing sale agreements from interruptible customers, and park and loan services provided by upstream pipelines.

As shown in Exhibit A to the petition, the current total annual expenses associated with providing swing service are $12,622,934 compared to $6,342,232 when the swing service charge was approved in 2000. However, the number of NCTS customers and associated therm usage has also increased in recent years, allowing Peoples to spread the increased swing service costs over more therms. Exhibit A to the petition also shows customer bill impacts of the revised swing charges for the various commercial rate schedules. Residential customers take sales service only and therefore do not pay a swing service charge.[3]

The swing service charge modifications proposed by Peoples include NCTS customers' portion of the reservation charges that Peoples would pay to SeaCoast Gas Transmission Company, L.L.C. (SeaCoast) pursuant to a firm transportation service agreement for which SeaCoast is requesting approval in Docket No. 150221-GU. In response to staff's data request, Peoples

[3] Very large residential customers using 2,000 therms or more annually must take service under Peoples' Small General Service tariff, and qualify for Rider NCTS.

provided information (confidential) regarding the amount of reservation charges that Peoples would pay SeaCoast under that transportation service agreement and the relative impact of those charges on Peoples' proposed swing service charge modifications in this docket. Based on a review of the information provided by Peoples, the reservation charges associated with the SeaCoast-Peoples transportation agreement would have a de minimis effect on Peoples' proposed swing service charge factors in this docket.

Conclusion

The swing service charge has not been updated during its 15-year existence and the number of NCTS customers has increased significantly during that time frame. Peoples stated in the instant petition that it contemplates periodic filings to update the swing service charge. Updating the costs associated with providing the system balancing service that the swing service charge is designed to recover ensures an appropriate allocation of costs between NCTS and sales customers. Based on a review of the petition and information provided by Peoples in response to staff's data request, staff believes that Peoples' proposed swing service charge tariff modifications are reasonable. Staff recommends that the Commission approve the tariff modifications to the swing service charge to become effective as of the date of the Commission's vote.

Issue 2: Should this docket be closed?

Recommendation: If Issue 1 is approved and 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. (Villafrate)

Staff Analysis: If Issue 1 is approved and 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.

Peoples Gas System
a Division of Tampa Electric Company
Original Volume No. 3

Fourth Revised Sheet No. 7.101-3
Cancels Third Revised Sheet No. 7.101-3

GENERAL APPLICABILITY PROVISIONS (Continued)

D. SWING SERVICE CHARGE

The Pool Manager of a Customer receiving aggregated transportation service from Company under the Natural Choice Transportation Service Rider (Rider NCTS) provides a fixed daily quantity of Gas supply and interstate pipeline transportation capacity throughout each month. The Company must increase or reduce the system's Gas supply and use of interstate pipeline capacity in an effort to balance the actual daily consumption of a Rider NCTS Customer as it differs from the fixed daily quantity of Gas being delivered by the Customer's Pool Manager during the month. The Swing Service Charge is assessed to firm Rider NCTS Customers to cover the costs incurred by the Company to maintain the above-described balance and distribution system integrity.

The bill for aggregated transportation service provided by Company to a firm Customer pursuant to Rider NCTS in any Billing Period shall be adjusted as follows:

The monthly consumption of each Rider NCTS Customer shall be multiplied by the Swing

Service Charge factors listed below, each factor being increased or decreased to the nearest $0.0001 per therm and include the regulatory assessment tax factor of 1.00503:

Rate Class	Recovery Factor
Small General Service	$0.0388~~0281~~ per Therm
Commercial Street Lighting	$0.0071~~0117~~ per Therm
Natural Gas Vehicle Service	$0.0435~~0289~~ per Therm
General Service 1	$0.0208~~0145~~ per Therm
General Service 2	$0.0217~~0126~~ per Therm
General Service 3	$0.0234~~0126~~ per Therm
General Service 4	$0.0079~~0126~~ per Therm
General Service 5	$0.0058~~0099~~ per Therm

Revenues derived from the Swing Service Charge are credited to the Purchased Gas Adjustment Clause to the extent applicable.

Issued By: Gordon L. Gillette, President
Issued On:
Effective:

Item 19

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Bruce, Hudson)
Division of Accounting and Finance (Archer, Buys, Cicchetti, Yeazel)
Division of Engineering (King, Watts)
Office of the General Counsel (Brownless)

RE: Docket No. 150102-SU – Application for increase in wastewater rates in Charlotte County by Utilities, Inc. of Sandalhaven.

AGENDA: 12/03/15 – Regular Agenda – Proposed Agency Action except Issue Nos. 19 and 24 – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Edgar

CRITICAL DATES: 12/05/15 (5-Month Effective Date (PAA Rate Case))

SPECIAL INSTRUCTIONS: None

Table of Contents

Case Background

Utilities, Inc. of Sandalhaven (Sandalhaven or utility) is a Class B wastewater utility serving 835 wastewater customers in Charlotte County. Water service to the area is supplied by Charlotte County. According to the utility's 2014 annual report, the utility had operating revenues of $668,757 and operating expenses of $841,708.

Sandalhaven has been in existence since 1983 and was granted an original certificate in 1995 following Charlotte County's adoption of a resolution giving the Florida Public Service Commission (Commission) jurisdiction over privately owned water and wastewater utilities.[1] Effective September 25, 2007, the Commission's jurisdiction was rescinded by Charlotte County and the certificate was cancelled.[2] Subsequently, in 2013, Charlotte County transferred jurisdiction back to the Commission. Effective February 12, 2013, Sandalhaven was granted Certificate No. 567-S.[3] The Commission set rate base for the utility in 2007.[4] However, the utility's current rates were established by Charlotte County, in Resolution 2012-209, adopted November 13, 2012, based upon a December 31, 2010 test year.

On June 4, 2015, Sandalhaven filed its application for the rate increase at issue in the instant docket. A deficiency letter was sent to the utility on July 1, 2015, and corrections to the minimum filing requirements (MFRs) were filed on July 6, 2015, which was established as the official date of filing pursuant to Section 367.083, Florida Statutes (F.S.). The utility requested that the application be processed using the Proposed Agency Action (PAA) procedure and requested interim rates. The test year established for interim and final rates is the period ended December 31, 2014. The utility is requesting an increase to recover reasonable and prudent costs for providing service and a reasonable rate of return on investment, including pro forma plant improvements. Sandalhaven requested an interim revenue increase of $724,062 (106.2 percent) and a final revenue increase of $939,540 (137.9 percent).

The system was originally designed to serve the communities in the northeastern part of the territory. The wastewater treatment plant (WWTP) was initially permitted for 150,000 gallons per day (gpd), and the treated effluent was disposed of as reclaimed water for irrigation at the Wildflower Golf Course (WGC). The utility was aware that WGC had been slated for residential development and would at that time, thus, be unavailable for effluent disposal. Due to the expected development of WGC, and having been approached by developers regarding growth, Sandalhaven began exploring options for handling the anticipated wastewater treatment demands. After studies that included interconnection with nearby utilities and expansion of the WWTP with the associated drilling of a deep-injection well for disposal, Sandalhaven opted for interconnection with Englewood Water District (EWD) as the least-cost solution, as was

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[1]Order No. PSC-95-0478-FOF-SU, issued April 13, 1995, in Docket No. 941341-SU, In re: *Application for certificate to provide wastewater service in Charlotte County by Sandalhaven Utility, Inc.*
[2]Order No. PSC-07-0984-FOF-WS, issued December 10, 2007, in Docket No. 070643-WS, In re: *Resolution No. 2007-143 by Charlotte County Board of Commissioners, in accordance with Section 367.171, F.S., rescinding Florida Public Service Commission jurisdiction over private water and wastewater systems in Charlotte County.*
[3]Order No. PSC-13-0178-FOF-SU, issued April 29, 2013, in Docket No. 130053-SU, In re: *Application for grandfather certificate to operate wastewater utility in Charlotte County by Utilities, Inc. of Sandalhaven.*
[4]Order No. PSC-07-0865-PAA-SU, issued October 29, 2007, in Docket No. 060285-SU, In re: *Application for rates in Charlotte County by Utilities, Inc. of Sandalhaven.*

acknowledged in the Commission's Order in the last rate case. The interconnection was completed in April 2007, and initially only served new customers from the southern portion of the utility's wastewater service territory. These customers had no connection to the WWTP, so interconnection with EWD was their only treatment option. With the installation of isolation valves at strategic locations, a few developments could be served by either EWD or the WWTP, but the oldest subdivisions could only be served by the WWTP until a project to redirect the flows from those customers was completed. Sandalhaven anticipated that, with the completion of this flow redirection project, it would seek to decommission its WWTP.

The flow redirection project (also referred to as a diversion project) was planned to be implemented with the application of Phase II rates in the utility's last Commission rate case. However, the Board of County Commissioners of Charlotte County (County) rescinded the Commission's jurisdiction of privately-owned water and wastewater systems during the pendency of the rate case. The Commission's Phase I rates were implemented, but the Phase II rates with the associated pro forma projects were not. During the period that Sandalhaven was regulated by the County (2007 to 2013), the utility petitioned for and received a rate increase from the County and the WWTP was rerated to 99,000 gpd in response to recommendations from a Capacity Analysis Report submitted to the Florida Department of Environmental Protection (DEP). When the County transferred jurisdiction back to the Commission in 2013, the rates and charges established by the County were approved. Sandalhaven did not proceed with the diversion project while under the County's jurisdiction.

In 2014, DEP received a complaint from representatives of the Fiddlers Green homeowners association regarding leaching of wastewater into surrounding areas. After investigation, DEP revised Sandalhaven's permitted capacity to 45,000 gpd. Sandalhaven directed all possible flows to the EWD interconnection, but were unable to divert the flows from the oldest developments. During peak occupancy times, the utility had no option but to exceed its permitted capacity due to the demand from these customers. Thus, in October 2014, DEP issued a Consent Order that required the utility to divert all flows from the WWTP to EWD and decommission the WWTP. The Consent Order directed the diversion project to be completed by October 1, 2015, with the decommissioning of the WWTP to be completed within 60 days of the diversion. The Consent Order contained penalties for failure to timely comply with these requirements unless the utility could show that any delay was due to circumstances beyond its control. Sandalhaven was unable to meet this deadline due to delays the power company experienced in getting necessary easements. The utility requested and received an extension from DEP. The diversion was completed November 2, 2015.

The Commission has jurisdiction in this case pursuant to Sections 367.011, 367.0814, 367.101, and 361.121, Florida Statutes (F.S.).

Discussion of Issues

Issue 1: Is the quality of service provided by Sandalhaven satisfactory?

Recommendation: Yes. The utility has taken reasonable actions to comply with DEP's consent order and to address customer concerns. All quality of service issues have been resolved. Staff recommends that the quality of service provided by the utility be considered satisfactory. (Watts)

Staff Analysis: Pursuant to Rule 25-30.433(1), Florida Administrative Code (F.A.C.), in water and wastewater rate cases, the Commission shall determine the overall quality of service provided by a utility, derived from an evaluation of three separate components of utility operations. These components are the quality of the utility's product, the operating conditions of the utility's plant and facilities, and the utility's attempt to address customer satisfaction. The rule further states that sanitary surveys, outstanding citations, violations, and consent orders on file with the DEP and the county health department over the preceding three-year period shall be considered in addition to customer comments or complaints.

Quality of Utility's Product and Operating Conditions of the Utility's Facilities

Sandalhaven provides wastewater service only. Although the utility no longer operates a WWTP, during the test year its operation of the wastewater treatment system was subject to various environmental requirements such as permitting, testing, and discharge monitoring under the jurisdiction of DEP. During the last two Compliance Inspections in 2011 and 2013, DEP found some minor out-of-compliance conditions at the WWTP, which were addressed by the utility. The overall operation of the plant was found to be satisfactory.

As noted in the case background, in 2014 DEP received a complaint from a customer regarding apparent leaching of wastewater from the percolation ponds to the surrounding area. After investigation and supplemental monitoring by the utility revealed that the percolation ponds were no longer able to handle the demand, the utility entered into a Consent Order with DEP. The Consent Order required the utility to: 1) prevent potential impacts on neighboring properties by following the protocol described in the monitoring plan approved by DEP; 2) construct a wastewater collection/transmission system to divert flow from the WWTP to the EWD interconnection force main; and 3) inactivate or abandon the WWTP within 60 days of diverting the flow to EWD.

The diversion was to be completed by October 1, 2015; however, due to circumstances beyond its control, the utility was unable to meet this deadline. It requested and received an extension. The diversion was complete on November 2, 2015, and the utility began the WWTP decommissioning process immediately afterward.

The utility had long contemplated decommissioning the WWTP and diverting all flows to EWD for economic reasons, and would have done so with the implementation of the Phase II rates set in its last rate case. However, with the subsequent jurisdictional changes, these projects were put on hold until the failure of the percolation ponds in 2014. It then became clear that the diversion and decommissioning projects must be implemented for the safety of the nearby residents and the environment.

Prior to the complaint to DEP, Sandalhaven had operated and maintained its plant in a satisfactory manner as indicated by DEP's August 4, 2011 and August 5, 2013 Compliance Inspection reports. Although leaching of wastewater from percolation ponds to the surrounding area is a serious problem with a lengthy resolution process, the utility acted responsibly by complying with all DEP requirements as expeditiously and economically as possible. When Sandalhaven was notified of the problem by DEP, it hired an engineering firm to determine the source. When the percolation ponds were determined to be the problem, the utility met with DEP and formulated a corrective action plan, which DEP approved. The utility then proceeded to implement its corrective action plan to resolve the problem. Staff believes Sandalhaven exercised caution by acting only under DEP supervision within DEP's consent order process. It appears Sandalhaven is complying with the terms of DEP's consent order.

On September 15, 2015, staff inspected the utility's plant. Although the WWTP is being decommissioned, staff inspected the 13 lift stations and observed that they were operational and in good repair. Based on Sandalhaven's status with DEP and staff's on-site observations, staff recommends that the operational condition of Sandalhaven's wastewater system is satisfactory.

The Utility's Attempt to Address Customer Satisfaction

A customer meeting was held on September 24, 2015, at the Tringali Community Center in Englewood, Florida. Of the 73 customers who were present at the meeting, 13 customers signed up to speak. As of November 17, 2015, 94 customers have sent written comments to the Commission. Four of the customers who sent written comments also spoke at the customer meeting. The majority of customers' comments, both written and spoken at the customer meeting, expressed objections to various aspects of the rate increase.

The rate increase objections ranged from general disagreement with raising the rates to statements regarding specific ratemaking elements such as return on equity, depreciation, and items that should or should not be considered in setting the rates. Since receiving Sandalhaven's request for a rate increase, staff has diligently analyzed the utility's books and records, and made its recommendation in accordance with the Commission's rules, statutes, and practices. As such, staff will address its treatment of these ratemaking elements in its customary manner in the appropriate issues.

In addition to the rate increase, the customers had concerns or questions about: (1) leakage from the WWTP; (2) paying for unrealized growth or future customers; (3) suggestions for alternative methods of determining the rate increase; and (4) the billing error related to interim rates. These concerns are discussed below.

Leakage

Several customers from the Fiddlers Green neighborhood, which is adjacent to the WWTP, expressed concern about wastewater from the percolation ponds leaching into the surrounding area, and the utility's slow response. However, the percolation ponds did not, at that point, have a history of failure, and the utility had no way of determining if they were the source of the standing water without pursuing a lengthy study. Given the utility's DEP obligations regarding the issue, its most responsible avenue was to address the issue with DEP through the complaint investigation and Consent Order process as stated earlier. Sandalhaven was given the results of DEP's complaint inspection on May 5, 2014. Within two months it had performed the study needed to determine that the percolation ponds were the source of the problem and met with DEP to discuss its proposed corrective action plan. Staff believes the utility did not delay taking action, but rather responded with appropriate caution.

As described in the case background, Sandalhaven has diverted all flows from the WWTP to EWD and is in the process of decommissioning the WWTP. Once this process is completed, staff believes the problems associated with living in close proximity to a WWTP, from odor to leakage to large sludge-hauling trucks, should be alleviated.

Growth

Several customers expressed a belief that the rate increase was either to pay for infrastructure built to support growth that did not materialize, or to fund future growth. Neither of these viewpoints is correct. In the last rate case, the utility did anticipate future growth based on developers that approached it for service to planned developments. With respect to the physical aspects of the system, at the beginning of the last rate case, the interconnection with EWD was not yet completed and all current customers were served by the WWTP. Prior to the Order being issued in that case, the interconnection was completed and available to serve new customers. Several of the customers who wrote to the Commission may not be aware that they are from some of the developments that can only be served by the interconnection to EWD.

With respect to the regulatory aspects of the last rate case, the Commission, on recognizing that many customers could still be served by the WWTP prior to the plant being decommissioned, ordered that the interconnection components-the force main, primary master lift station, and the purchased treatment capacity-be assigned a non-used and useful adjustment for the Phase I rates. This shielded the current customers from paying for future growth. The interconnection was completed in April 2007, and initially only served new customers from the southern portion of the utility's wastewater service territory. These customers had no connection to the WWTP, so interconnection with EWD was their only treatment option.

The capacity payments made in 2006 and 2007, included capacity needed for current, active customers and for the equivalent residential connections (ERCs) prepaid for by developers. Thus, the customers who were active at that time only paid their pro rata share for the capacity. As for the interconnection force main and the primary master lift station, the incremental costs of installing differently-sized pipes and fittings is incidental. This is because the major cost drivers of installing any size pipeline are the surveys, route selection, permitting, easements, excavation, etc., which would have to be paid each time new lines are installed. For this reason alone any responsible utility should size a force main to handle maximum expected flow. However, a force main only two inches smaller in diameter would have required pumping capacity more than three times higher than for the 12-inch force main that was installed, making the ongoing operational costs much higher over time. With the purchased treatment capacity being necessary to provide service to customers in the southern portion of its territory, the utility took advantage of economies of scale by avoiding the virtual doubling of labor costs (that would now have to be borne by current customers in the instant rate case), as well as greatly improving the operational efficiency of the system (saving on operation and maintenance costs since inception).

Likewise, according to the utility, the primary master lift station's receiving well was sized for maximum future usage, for the same reasons as the force main (the incremental materials cost is incidental compared to paying for labor multiple times to change it out as demand increases), but the pumps installed were sized to handle current demand to keep operating costs lower. Staff believes this was prudent since the cost to upgrade the pumps when needed is much less than the other master lift station components.

Now that the WWTP can no longer be used to provide wastewater treatment to any customers, all of Sandalhaven's customers are being served by the interconnection to EWD. The WWTP, prior to decommissioning, was incapable of handling the demand for even a fraction of Sandalhaven's customers connected to it, much less all of its current customers, so the utility had to have additional capacity. Because of the utility's actions in selecting the most cost-effective long term solution, together with the regulatory treatment from the last rate case and that proposed in the instant case, Sandalhaven's customers have been adequately shielded from the cost impacts of investment for future customers.

Customers' Suggested Alternatives for Determining a Rate Increase

Some of the alternative rate increase treatments suggested by customers included tying the percentage increase to inflation or to cost-of-living increases, keeping the interim rates, or making them equivalent to the rates of nearby city or county utilities. Staff cannot make its recommendation based on these principles, but must abide by the requirements of the Commission's rules and statutes.

Billing Error

The Commission granted the utility an interim rate increase. The customers were noticed of the correct interim rates. However, due to an administrative error, the customers' August bill did not reflect the correct interim rates approved by the Commission effective July 29, 2015. When the error was discovered, the utility worked with staff to resolve the issue. The utility indicated that when customers called they would advise them of the course of action being taken to resolve the issue. Also, the utility worked with staff to draft language to include in its next billing cycle, which indicated that the bill reflects the accurate lower interim rates and includes a credit to correct the prior billing error. Further, staff's customer meeting was held prior to the utility being able to get the bill issued and at that time, staff advised the customers the course of action being taken to correct the error.

Staff reviewed the complaints in the Commission's Complaint Tracking System for Sandalhaven from January 1, 2009, through November 5, 2015. Staff found 12 complaints for this system filed with the Commission. All of these were billing complaints regarding the utility's erroneous application of its requested interim rates instead of its Commission-approved interim rates. The utility resolved these complaints. No quality of service problems were reported to the Commission.

A summary of all complaints and comments received is shown in Table 1-1.

Table 1-1
Number of Complaints by Source

Subject of Complaint	PSC's Records (CATS)	Utility's Records	DEP Records	Docket Correspondence	Customer Meeting
Billing Related	12	2		4	6
Opposing Rate Increase				83	13
Other[5]		3			
Quality of Service		4	3	4	3
Total*	12	9	3	91	22

* A complaint may appear twice in this table if it meets multiple categories.

Summary

The utility has taken reasonable actions to comply with DEP's consent order and to address customer concerns. All quality of service issues have been resolved. Staff recommends that the quality of service provided by the utility be considered satisfactory.

[5] Found not to be the Utility's issue.

Issue 2: Should the audit adjustments to rate base and operating expense to which the utility and staff agree be made?

Recommendation: Yes. Based on the audit adjustments agreed to by the utility and staff, the following adjustments should be made to rate base and net operating income as set forth in staff's analysis below. (D. Buys)

Staff Analysis: In its response to the staff audit reports of the utility and affiliate transactions, Sandalhaven agreed to the audit adjustments as set forth in the tables below.

Table 2-1
Description of Audit Adjustments

Audit Finding	Description of Adjustment
Audit Finding No. 1 – Sandalhaven	Reflect the appropriate UPIS balances.
Audit Finding No. 4 – Sandalhaven	Reflect the appropriate Land balance.
Audit Finding No. 6 – Sandalhaven	Reflect the appropriate amount of operating revenue and RAFs.
Audit Finding No. 8 – Sandalhaven	Reflect the appropriate amount of O&M Expense.
Audit Finding No. 1 – Affiliate (UI)	Reflect the correct allocated plant and accumulated depreciation for Transportation.
Audit Finding No. 2 – Affiliate (UI)	Reflect the correct allocated UPIS, accumulated depreciation and depreciation expense.

Source: Staff audit and utility responses to staff data request

Based on the audit adjustments agreed to by the utility, staff recommends that the adjustments set forth in Tables 2-2 and 2-3 be made to rate base and net operating income.

Table 2-2
Adjustments to Rate Base

Audit Finding	Plant	Land	Accumulated Depreciation
Audit Finding No. 1 – Sandalhaven	($14,954)		$3,707
Audit Finding No. 4 – Sandalhaven		$10,000	
Audit Finding No. 1 – Affiliate (UI)	($7,289)		$22,689
Audit Finding No. 2 – Affiliate (UI)	($10,968)		$3,578
Total	($33,211)	$10,000	$29,974

Source: Staff audit and utility responses to staff data request

Table 2-3
Adjustments to Net Operating Income

Audit Finding	Depreciation Expense	O&M Expense	Revenue	TOTI
Audit Finding No. 1 – Sandalhaven	($778)			
Audit Finding No. 6 – Sandalhaven			($17,939)	($807)
Audit Finding No. 8 – Sandalhaven		$21,499		
Audit Finding No. 1 – Affiliate (UI)	$19,381			
Total	$18,603	$21,499	($17,939)	($807)

Source: Staff audit and utility responses to staff data request

Issue 3: Should any further adjustments be made to test year rate base?

Recommendation: Yes. Plant should be decreased by $23,335, accumulated depreciation should be decreased by $297,173, CIAC should be increased by $258,674, and accumulated amortization of CIAC should be increased by $19,536. Corresponding adjustments should also be made to increase net depreciation expense by $6,160. Staff recommends that Sandalhaven reflect any change in property taxes in its next pass through filing with the Commission. The amortization expense related to the cost of removal of the WWTP should be decreased by $642 to $9,770 and amortized over a period of 10 years. After the expiration of the amortization period, the wastewater rates should be reduced by $9,770, as shown on Schedule No. 4, to remove removal costs grossed-up for regulatory assessment fees (RAFs) and amortized over a 10-year period. The decrease in rates should become effective immediately following the expiration of the 10-year recovery period of removal costs associated with the decommissioning of the utility's WWTP. Sandalhaven 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 expense. (D. Buys)

Staff Analysis:

Retirement of Wastewater Treatment Plant

In its filings, Sandalhaven made adjustments to reflect the retirement of its WWTP. Plant was decreased by $1,061,091, accumulated depreciation was decreased by $787,253, CIAC was decreased by $1,310,499, and accumulated amortization of CIAC was decreased by $1,071,361. Staff had concerns regarding the utility's retirement calculations and after several inquiries, the utility provided revised calculations in its response to staff's fifth data request filed on October 26, 2015. Sandalhaven's revised adjustments included retirements to plant of $1,084,426, accumulated depreciation of $1,084,426, CIAC of $1,051,825, and accumulated amortization of CIAC of $1,051,825. Upon review of the staff audit and the utility's responses to several data requests, staff believes the revised adjustments to retire the wastewater treatment plant are appropriate.

The utility is proposing to retire CIAC of $1,051,825 due to the retirement of the wastewater treatment plant. Sandalhaven identified $628,734 of CIAC associated with Account 354.4 Structures & Improvements, $62,927 associated with Account 380.4 Treatment & Disposal, $185 associated with Lagoons, and $359,979 associated with plant capacity fees received from developments served prior to 2004. The total CIAC balance for the test year ended December 31, 2014, was $3,276,640. The utility is proposing to retire 32.1 percent of the total CIAC ($1,501,825 ÷ $3,276,640). The WWTP served approximately 855 ERCs. The total ERCs that could be served by the wastewater system (the WWTP plus the prepaid capacity at EWD) is approximately 2,175 ERCs. The ERC percentage served by the WWTP is 39.3 percent of the system capacity. Based on a comparison of the percentage of ERCs served by the WWTP (32 percent) to the percentage of CIAC associated with the WWTP (39 percent), staff believes the utility's proposal to retire CIAC of $1,051,825 is appropriate and reasonable.

The utility's proposed plant balance retirement of $1,084,426 is based on the simple average balances of the plant accounts associated with the retirement of the WWTP. All additions and reclassifications to the treatment plant account balances since the prior rate case in Docket No. 060285-SU have been audited by staff and are fully supported by the utility. The WWTP was permanently taken offline on November 2, 2015, and the decommissioning process subsequently commenced. In its current filing, the utility did not record any salvage value of the plant components associated with the decommissioning of the WWTP. However, should the utility recover salvage value upon the completion of the decommissioning of the WWTP, staff recommends it be addressed in Sandalhaven's next rate case once the value is known.

Rule 25-30.140(9)(a), F.A.C., states:

> (a) Beginning with the year ending December 31, 2003, all Class A and B utilities shall maintain separate sub-accounts for: (1) each type of Contributions-in-Aid-of-Construction (CIAC) charge collected including, but not limited to, plant capacity, meter installation, main extension or system capacity; (2) contributed plant; (3) contributed lines; and (4) other contributed plant not mentioned previously. Establishing balances for each new sub-account may require an allocation based upon historical balances. Each CIAC sub-account shall be amortized in the same manner that the related contributed plant is depreciated. Separate sub-accounts for accumulated amortization of CIAC shall be maintained to correspond to each sub-account for CIAC.

In its filing, the utility reflected total CIAC amortization expense of $25,074, which included an amount of $1,869 classified as "tap fees." In its revised WWTP retirement calculations, Sandalhaven included a CIAC balance $359,979 for tap fees, but did not provide revised calculations for CIAC amortization expense. The appropriate amortization rate for tap fees is 0.025. Staff believes the CIAC amortization expense of $1,869 is understated and should be $8,999 ($359,979 x 0.025). The total CIAC amortization expense retired should be $32,154. As a result, CIAC amortization expense should be increased by $7,080.

In its MFRs, the utility reflected an adjustment to decrease depreciation expense by $43,176, or a net decrease to depreciation expense of $18,102 ($43,176 - $25,074). The depreciation expense associated with the utility's revised plant retirement calculation is $44,096, or a decrease of $920 from the amount included in the utility's MFRs. The increase to net depreciation expense is $6,160 ($7,080 - $920). Accordingly, staff recommends net depreciation expense should be increased by $6,160.

Staff believes that property taxes should be reduced to reflect the retirement and decommissioning of the WWTP. Staff recommends that the utility be required to contact the Charlotte County Tax Appraiser about revising the appraised tangible property value. Staff recommends that Sandalhaven reflect any change in property taxes in its next pass through filing with the Commission.

Based on the aforementioned, staff recommends that plant be decreased by $23,335, accumulated depreciation be decreased by $297,173, CIAC be increased by $258,674, and accumulated amortization of CIAC be increased by $19,536. Corresponding adjustments should also be made to decrease depreciation expense by $920 and increase CIAC amortization expense by $7,080, or a net increase to depreciation expense of $6,610.

Net Loss on Forced Abandonment

In its filing, Sandalhaven reflected an amortization expense of $10,412 amortized over 14.43 years to recover a net loss on abandonment of $150,237. In its filing, the utility estimated a cost of $156,000 to decommission the WWTP. In response to a staff data request, Sandalhaven provided an invoice for a cost of $97,696 to decommission the WWTP. Based on the retirement adjustments discussed above, the utility will incur a net loss on forced abandonment of $97,696 based solely on the cost of removal and decommissioning of the WWTP.

Table 3-1
Net Loss on Forced Abandonment

Plant Balance	$1,084,426
Less Depreciation	$1,084,426
Less CIAC	$1,051,825
Plus Amortization of CIAC	$1,051,825
Net Loss on Rate Base	$0
Plus Cost to Remove	$97,696
Net Loss	$97,696

Source: Utility's response to staff data requests

Rule 25-30.433(9), F.A.C., Rate Case Proceedings, states:

> The amortization period for forced abandonment or the prudent retirement, in accordance with the National Association of Regulatory Utility Commissioners Uniform System of Accounts, of plant assets prior to the end of their depreciable life shall be calculated by taking the ratio of the net loss (original cost less accumulated depreciation and contributions-in-aid-of-construction (CIAC) plus accumulated amortization of CIAC plus any costs incurred to remove the asset less any salvage value) to the sum of the annual depreciation expense, net of amortization of CIAC, plus an amount equal to the rate of return that would have been allowed on the net invested plant that would have been included in rate base before the abandonment or retirement. This formula shall be used unless the specific circumstances surrounding the abandonment or retirement demonstrate a more appropriate amortization period.

For the purpose of calculating the amortization period pursuant to Rule 25-30.433(9), F.A.C., the net loss is $97,696 divided by zero, which results in zero years. Hence, Rule 25-30.433(9), F.A.C., is not applicable in this case since the retired asset is fully depreciated. Pursuant to Rule

25-30.433(8), F.A.C., non-recurring expenses shall be amortized over a 5-year period unless a shorter or longer time can be justified. In this case, staff believes a recovery period of 10 years is appropriate and recommends the net loss of $97,696 be amortized over a 10-year period. Staff's recommendation is consistent with the Commission's recent decision regarding the Orchid Springs Development staff assisted rate case in Docket No. 140239-WS at the November 5, 2012 Agenda Conference.[6] The amortization amount equates to the net loss of $97,696 divided by 10 years, or $9,770. The resulting adjustment is a decrease to amortization expense of $642 from the utility's proposed amortization expense of $10,412. Accordingly, staff recommends that amortization expense be decreased by $642 to $9,770 and amortized over a period of 10 years.

Based on the above analysis, staff recommends that plant be decreased by $23,335, accumulated depreciation be decreased by $297,173, CIAC be increased by $258,674, and accumulated amortization of CIAC be increased by $19,536. Corresponding adjustments should also be made to increase net depreciation expense by $6,160. Staff recommends that Sandalhaven reflect any change in property taxes in its next pass through filing with the Commission. The amortization expense related to the cost of removal of the WWTP should be decreased by $642 to $9,770 and amortized over a period of 10 years. After the expiration of the amortization period, the wastewater rates should be reduced by $9,770, as shown on Schedule No. 4, to remove removal costs grossed-up for regulatory assessment fees (RAFs) and amortized over a 10-year period. The decrease in rates should become effective immediately following the expiration of the 10-year recovery period of removal costs associated with the decommissioning of the utility's WWTP. Sandalhaven 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 expense.

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[6] Docket No. 140239-WS, *In re: Application for staff-assisted rate case in Polk County by Orchid Springs Development Corporation.*

Issue 4: Should any adjustments be made to the utility's pro forma plant?

Recommendation: Yes. Pro forma plant should be decreased by $153,873. Corresponding adjustments should be made to decrease accumulated depreciation and depreciation expense by $4,870. An additional corresponding adjustment should be made to decrease credit ADITs by $481. (Watts, D. Buys)

Staff Analysis: Section 367.081, F.S., provides that the Commission, in fixing rates, shall consider facilities to be constructed within a reasonable time in the future, to be Used and Useful (U&U) if such property is needed to serve current customers. Costs associated with each of the pro forma plant items discussed below have been or are projected to be incurred within two years of the test year. Section 367.081, F.S., additionally provides that the Commission shall approve rates for service which allow a utility to recover the full amount of environmental compliance costs.

Sandalhaven's initial filing contained two pro forma plant additions. Staff reviewed the utility's filings and responses to data requests and recommends that several adjustments to the utility's requested pro forma plant additions are necessary. Table 4-1 provides a summary of staff's recommended pro forma plant additions.

Table 4-1
Staff Recommended Pro Forma Plant Adjustments

Pro Forma Plant Items	Initial MFR	Response from data request / Filing	Recommended Amount	Documentation
Diversion from WWTP to EWD	$696,129	$743,672	$742,256	Invoice / Work Order
Relocation of sewer pipe due to County road construction.	$200,000	$174,088	$0	Engineering estimate / utility opinion of probable construction cost
Total	$896,129	$917,760	$742,256	

Source: MFRs and utility's response to staff data requests

The work for the pro forma project to divert the flow from the WWTP to the EWD wastewater treatment plant was completed on November 2, 2015, and the flows have been diverted. The utility provided invoices for the work performed, and also provided schedules reflecting the capitalized time for Sandalhaven employees and interest expense during construction as support for the cost of the project. There was a retirement of $1,417 included in the upgrade of one of the lift stations. As such, staff's recommended amount of $742,256 reflects the removal of the retirement from the utility's requested amount of $743,672.

The utility requested a pro forma plant increase of $200,000 to recover the cost to relocate existing sewer lines due to road improvements by Charlotte County. Staff believes the utility has not supported the requested amount. The utility plans to complete its project in coordination with Charlotte County's construction schedule and assumes that the project will commence on July 1, 2016, and be completed on December 31, 2016. However, the actual completion date of the project is dependent upon Charlotte County's work schedule which is unknown at this time. Charlotte County's website indicates that as of November 17, 2015, permitting for this project is 85 percent complete and the construction schedule is yet to be determined. Further, the utility has not obtained any construction bids for the project. The utility submitted a self-prepared document entitled "Placida Road Force Main Relocations Opinion of Probable Construction Cost" which is not a signed bid for the construction cost of the project.

In its MFRs, Sandalhaven included a credit adjustment of $852 to the ADITs balance to account for the deferred taxes associated with the addition of pro forma plant. Staff's recommended adjustments to decrease pro forma plant result in a corresponding decrease to the deferred taxes associated with the pro forma plant additions. Based on the utility's calculation of ADITs associated with the pro forma plant additions included in the staff audit work papers, staff believes the appropriate amount of credit ADITs associated with the pro forma projects is $371. Accordingly, staff recommends that credit ADITs of $852 be decreased by $481 to $371.

Based on the aforementioned, staff believes the pro forma amounts in Table 4-1 are appropriate. Accordingly, staff recommends that plant be decreased by $153,873. Corresponding adjustments should be made to decrease accumulated depreciation and depreciation expense by $4,870. An additional corresponding adjustment should be made to decrease credit ADITs by $481.

Issue 5: What are the used and useful percentages for the utility's wastewater collection and interconnection systems?

Recommendation: Sandalhaven's wastewater collection system, purchased wastewater treatment capacity, and primary master lift station should be considered 100 percent used and useful (U&U); and its interconnection force main should be considered 74.9 percent U&U. To reflect the appropriate U&U percentages, staff recommends that plant be decreased by $755,064, accumulated depreciation be decreased by $252,979, CIAC be decreased by $19,144, and accumulated amortization of CIAC be decreased by $7,337. In addition, Land should be decreased by $4,662. Corresponding adjustments should be made to decrease depreciation expense and amortization expense by $26,089 and $637, respectively. As such, rate base should be decreased by $490,278 and net depreciation expense should be decreased by $25,451. Staff recommends that wastewater purchased power, chemical expenses, and purchased wastewater treatment should be reduced by 26.07 percent for excessive infiltration and inflow (I&I). (Watts, D. Buys)

Staff Analysis: The Sandalhaven wastewater system is composed of purchased wastewater treatment capacity through an interconnection with EWD, an interconnection force main, a primary interconnection master lift station, and a collection system. During the test year, a portion of the flows were treated by the utility's WWTP. Staff recommended the WWTP be considered 100 percent U&U for interim purposes. However, all flows are now directed to EWD for treatment, so no U&U percentage is needed for the WWTP.

Although the Commission's rules regarding U&U plant for wastewater treatment systems do not address purchased treatment capacity or interconnection plant, staff believes that a U&U analysis is appropriate for these items. Each of these items has unique characteristics that need to be taken into account. The purchased treatment capacity is most analogous to a conventional WWTP, and staff's analysis of the purchased capacity will closely parallel that of a WWTP. Staff believes the functional nature of the interconnection components warrants a slightly different treatment, using peak flows instead of average flows.

Infiltration and Inflow

Typically, infiltration results from groundwater entering a wastewater collection system through broken or defective pipes and joints; whereas, inflow results from water entering a wastewater collection system through manholes or lift stations. By convention, the allowance for infiltration is 500 gpd per inch diameter pipe per mile, and an additional 10 percent of residential water billed is allowed for inflow. Rule 25-30.432, F.A.C., provides that in determining the amount of U&U plant, the Commission will consider I&I. Additionally, adjustments to operating expenses such as chemical and electrical costs are also considered necessary.

All wastewater collection systems experience I&I. The conventions noted above provide guidance for determining whether the I&I experienced at a WWTP is excessive. While Sandalhaven no longer operates a WWTP, the effects of excessive I&I affect the flows billed to Sandalhaven. Staff calculates the allowable infiltration based on system parameters and allowable inflow based on water sold to customers. The sum of these amounts is the allowable I&I. Staff next calculates the estimated amount of wastewater returned to the EWD from customers. The estimated return is determined by summing 80 percent of the water sold to residential customers with 90 percent of the water sold to non-residential customers. Adding the estimated return to the allowable I&I yields the maximum amount of wastewater that should be treated by EWD without incurring adjustments to operating expenses. If this amount exceeds the actual amount treated, no adjustment is made. If it is less than the gallons treated, then the difference is the excessive amount of I&I.

The utility has 2,325 feet of 6-inch and 11,670 feet of 8-inch collecting mains. Given these parameters and performing the necessary conversions to express the result in gallons per year (gpy), the allowance for infiltration is 3,709,105 gpy.

The utility's records indicated that it billed for wastewater based on 19,343,000 gallons of water demand for its residential customers and 17,303,000 gallons of water demand for its non-residential customers during the test year. Thus, the allowance for inflow is 10 percent of the residential flow, or 1,934,300 gpy. Therefore, the total allowance for inflow and infiltration is 5,643,405 gpy.

The utility reported the total number of water gallons billed to all wastewater customers during the test year was 36,646,000 gallons (19,343,000 residential, 17,303,000 non-residential). Estimating the residential return at 80 percent and the non-residential return at 90 percent, the total estimated return to the EWD is 31,047,100 gallons. Thus, the estimated maximum amount of wastewater that the EWD should treat, the estimated return plus the allowable I&I, is 36,690,505 gpy. Any amount treated in excess of this amount is considered excessive I&I.

According to the utility's MFR Schedule F-2, the utility treated 49,632,000 gallons of wastewater (including flows to EWD) during the test year. This is greater than the estimated maximum amount allowable. Therefore, the excessive I&I is 12,941,495 gpy, or 35,456 gpd. Expressed as a percentage of wastewater treated, excessive I&I is 26.07 percent.

Thus, a 26.07 percent adjustment to wastewater purchased power, chemical expenses, and purchased wastewater treatment should be made for excessive I&I as discussed in Issue 13.

Purchased Wastewater Treatment Capacity

The treatment capacity from EWD was purchased in two increments in 2006 and 2007 on an annual average daily flow (AADF) basis for a total of 300,000 gpd. The amount of capacity purchased was based on the utility's current demand, plus guaranteed revenue agreements for the Eagles Preserve Drive landowners, plus prepaid commitments from the developers noted in the case background. While not all of the growth materialized as expected, some of it did, and recently work has begun again on some of the previously planned developments. Staff recommends that the estimated flows for the unbuilt guaranteed revenue and prepaid customers should be included in the U&U calculations because, having already been paid for the capacity, the utility is obligated to be capable of providing service to these customers on demand.

According to Rule 25-30.432, F.A.C., the U&U analysis of a utility's WWTP is based on customer demand compared with the permitted plant capacity, with customer demand measured on the same basis as permitted capacity. As stated earlier, purchased capacity is similar to, but not the same as, a WWTP. Sandalhaven's contract with EWD is for 300,000 gpd on an AADF basis. Consideration is given for growth and I&I. Pursuant to Rule 25-30.431, F.A.C., a linear regression analysis of the utility's historical growth pattern results in 87 ERCs per year for the five-year statutory growth period. The utility had an average of 873 ERCs for the test year, resulting in 155.8 gpd/ERC (135,978 gpd/873 ERCs). Thus, a growth allowance of 67,755 gpd is also considered. Based on the sum of the AADF for the WWTP during the test year of 72,501 gpd, the 63,477 AADF treated by EWD during the test year, the estimated guaranteed revenue flows of 12,920 gpd, and the estimated prepaid commitment flows of 152,570 gpd, with the purchased capacity of 300,000 gpd, the growth allowance of 67,755 gpd, and the excessive I&I of 35,456 gpd, staff recommends that the purchased wastewater treatment capacity be considered 100 percent U&U. [(72,501 gpd + 63,477 gpd + 12,920 gpd + 152,570 gpd - 35,456 gpd + 67,755 gpd)/300,000 gpd]

Interconnection Force Main

As alluded to earlier, the physical properties of the interconnection force main necessitates sizing it for expected peak flow rather than for an average flow. This is because the pipe size limits the maximum flow. If demand exceeds this limit, it could cause line rupture, pump failure, equipment damage, and/or loss of service. The only peak flow data available for the test year was for the WWTP, as contained in the Discharge Monitoring Reports submitted to DEP. For the test year, the peak flow treated at the WWTP was 147,000 gpd, or 2.03 times the AADF. Thus, staff used this factor in estimating test year peak flows for EWD, guaranteed revenue and prepaid commitments. These same values will be used for the primary master lift station calculation below.

The U&U calculations for the interconnection force main and primary master lift station are as follows. Using peak flow data to determine a growth allowance yields 137,526 gpd at 316.2 gpd/ERC. Excessive I&I is not considered separately, being included in the peak flow data. Thus, based on test year peak WWTP flows of 147,000 gpd, EWD peak flows of 129,000, peak guaranteed revenue flows of 26,228 gpd, peak prepaid commitment flows of 309,717, a growth allowance of 137,526 gpd, and the interconnection force main capacity of 1,000,000 gpd, staff recommends the interconnection force main be considered 74.9 percent U&U. [(147,000 gpd + 129,000 gpd + 26,228 gpd + 309,717 gpd + 137,526 gpd)/1,000,000 gpd] The U&U adjustment of 74.9 percent for the force main should be applied to NARUC Account Nos. 355.2, Power Generation Equipment, and 360.2, Collection Sewers – Force.

Primary Master Lift Station

The U&U calculation for the primary master lift station is similar to the interconnection force main, with one difference. While the interconnection force main must deliver all flows from the Sandalhaven wastewater service territory to EWD, the primary master lift station will process all flows except that from the area previously only capable of being served by the WWTP. The flows from this area will be delivered directly to the interconnection force main by the secondary master lift station that is part of the diversion project that is among the pro forma items in the instant docket. Thus, the WWTP flows have been omitted from this calculation.

Based on test year peak EWD peak flows of 129,000, peak guaranteed revenue flows of 26,228 gpd, peak prepaid commitment flows of 309,717, a growth allowance of 137,526 gpd, and the primary master lift station capacity of 500,000 gpd, staff recommends the interconnection force main be considered 100 percent U&U. [(129,000 gpd + 26,228 gpd + 309,717 gpd + 137,526 gpd)/500,000 gpd]

Collection System

In the utility's last rate case the Commission found the wastewater collection system should be 100% U&U because virtually all of the wastewater mains and lift stations were contributed by the developers. Since that time there have been no changes to the collection system; therefore, staff recommends that the wastewater collection system should be considered 100% U&U

Land

As indicated in the utility's MFRs, a used and useful adjustment of 46.54 percent was applied to the Land balance of $157,062 to reflect the portion of land not used to provide service to customers. This same adjustment should be applied to the agreed upon audit adjustment in Issue 2 to increase land by $10,000. Accordingly, Land should be decreased by $4,662 to reflect the appropriate used and useful amount.

Summary

Based on the analysis above, staff recommends Sandalhaven's wastewater collection system, purchased wastewater treatment capacity, and primary master lift station should be considered 100 percent U&U; and its interconnection force main should be considered 74.9 percent U&U. To reflect the appropriate U&U percentages, staff recommends that plant be decreased by $755,064, accumulated depreciation be decreased by $252,979, CIAC be decreased by $19,144, and accumulated amortization of CIAC be decreased by $7,337. In addition, Land should be decreased by $4,662. Corresponding adjustments should be made to decrease depreciation expense and amortization expense by $26,089 and $637, respectively. As such, rate base should be decreased by $490,278 and net depreciation expense should be decreased by $25,451. Staff recommends that wastewater purchased power, chemical expenses, and purchased wastewater treatment should be reduced by 26.07 percent for I&I.

Issue 6: What is the appropriate working capital allowance?

Recommendation: The appropriate working capital allowance is \$70,647. As such, the working capital allowance should be decreased by \$16,610. (Yeazel, D. Buys)

Staff Analysis: Rule 25-30.433(2), F.A.C., requires that Class B utilities use the formula method, or one-eighth of O&M Expense, to calculate the working capital allowance. The utility properly filed its allowance for working capital using the one-eighth of O&M expense method and reflected a working capital allowance of \$87,257 in its MFRs. Staff has recommended adjustments to Sandalhaven's O&M expenses, which are reflected on Schedule No. 3-A. As a result, staff recommends a working capital allowance of \$70,647. This reflects a decrease of \$16,610 to the utilities requested working capital allowance.

Issue 7: What is the appropriate rate base for the test year period ended December 31, 2014?

Recommendation: Consistent with staff's other recommended adjustments, the appropriate rate base for the test year ended December 31, 2014, is $3,561,327. (D. Buys)

Staff Analysis: In its Revised MFRs, the utility requested a rate base of $4,721,216. Based on staff's recommended adjustments, the appropriate rate base is $3,561,327. Staff's adjustments recommended in the preceding issues result in a decrease of $1,159,890. The schedule for rate base is attached as Schedule No. 1, and the adjustments are shown on Schedule No. 1-A.

Issue 8: What is the appropriate return on equity?

Recommendation: Based on the Commission leverage formula currently in effect, the appropriate allowed return on equity (ROE) is 10.36 percent with a range of plus or minus 100 basis points. (Archer)

Staff Analysis: The ROE included in the utility's Revised MFRs is 10.37 percent. Based the current leverage formula in effect and an equity ratio of 49.78 percent, the appropriate allowed ROE is 10.36 percent. Staff recommends a range of plus or minus 100 basis points be recognized for ratemaking purposes.

Issue 9: What is the appropriate balance of accumulated deferred income taxes?

Recommendation: The appropriate 2014 average net used and useful credit accumulated deferred income taxes (ADITs) balance to include in the capital structure is $214,874. (D. Buys)

Staff Analysis: In its MFRs, the utility included a debit ADIT balance of $540,000 in its rate base. Staff believes two adjustments to the utility's ADITs are necessary. The adjustments involve the appropriate ratemaking treatment of the utility's ADITs for taxes paid on plant capacity charges and whether the debit ADITs for a net operating loss (NOL) should be disallowed.

Sandalhaven included a debit ADIT amount of $618,138 associated with income taxes the utility paid on plant capacity fees received from property developers. Sandalhaven believes that IRS Treasury Regulation 1.118-2 requires the utility to treat plant capacity charges as taxable income. Staff believes that IRS Treasury Regulation 1.118-2 clearly demonstrates that, in this case, Sandalhaven's plant capacity charges are non-taxable CIAC. In support of its position, the utility provided tax return documents showing it paid income taxes on the plant capacity fees of $895,000 in 2006. Specifically, the document included an entry for other income of $895,000 from service line and meter fees. In addition, the utility provided a memorandum from Price WaterhouseCoopers dated December 22, 2004. The memorandum indicated that PriceWaterhouseCoopers reviewed and signed the U.S. Corporation Income Tax returns for tax years 2001, 2002, and 2003, filed by Sandalhaven's parent company, Utilities, Inc. The memo stated:

> For the above mentioned income tax returns, plant modification fees and tap/connection fees were properly included in taxable income on each tax return under the provisions of the Internal Revenue Code Section 118 and the Income Tax regulations thereunder.

Paragraph (b)(3) of IRS Treasury Regulation 1.118-2 states that a customer connection fee is not a contribution in aid of construction under paragraph (b) and generally is included in taxable income. The utility classified the CIAC received from developers as tap fees, or service line or meter fees. Based on the utility's classification, it is understandable that a reasonable person could conclude that the CIAC is taxable under the utility's interpretation of IRS Treasury Regulation 1.118-2.

Staff believes that the CIAC collected from the developers does not meet the definition of a customer connection fee as defined by Paragraph (b)(3)(i) of IRS Treasury Regulation 1.118-2, which states:

> The term *customer connection fee* includes any amount of money or other property transferred to the utility representing the cost of installing a connection or service line (including the cost of meters and piping) from the utility's main water or sewer lines to the line owned by the customer or potential customer.

The CIAC in question consists mostly of payments from multiple developers from 1995 through 2006 to the utility to reserve capacity from the utility to serve potential residents in the planned developments. The amount of the plant capacity fee collected from the developers was based upon the Commission approved plant capacity fee of $1,250 per ERC listed in Sandalhaven's tariff. The amount of CIAC received was $1,573,581 which resulted in deferred taxes of approximately $592,138.

Staff also believes that IRS Treasury Regulation 1.118-2 clearly demonstrates that Sandalhaven's plant capacity charges are non-taxable CIAC. The characteristics to meet the definition of non-taxable CIAC are: (1) the money must be contributed to a regulated public utility that provides either water or sewer disposal services; (2) the contribution must provide for the expansion, improvement, or replacement of the utility's facilities; and (3) the contribution cannot be included in the utility's rate base for rate-making purposes. The CIAC collected by the utility meets all of these characteristics.

Further, if the CIAC received from the developers is considered a customer connection fee, staff believes that paragraph (b)(4)(i) of IRS Treasury Regulation 1.118-2 clearly demonstrates that Sandalhaven's plant capacity charges meet the exception whereby the CIAC is non-taxable if the charges were approved within 8½ months from the in-service date of the wastewater treatment plant. Paragraph (b)(4)(ii) of IRS Treasury Regulation 1.118-2, states:

> (ii) Example. The application of paragraph (b) (4) (i) of this section is illustrated by the following example:
>
> Example. M, a calendar year regulated public utility that provides water services, spent $1,000,000 for the construction of a water facility that can serve 200 customers. M placed the facility in service in 2000. In June 2001, the public utility commission that regulates M approves a tariff requiring new customers to reimburse M for the cost of constructing the facility by paying a service availability charge of $5,000 per lot. Pursuant to the tariff, M expects to receive reimbursements for the cost of the facility of $100,000 per year for the years 2001 through 2010. The reimbursements are contributions in aid of construction under paragraph (b) of this section because no later than 8½ months after the close of the taxable year in which the facility was placed in service there was a tariff, binding under local law, approved by the public utility commission requiring new customers to reimburse the utility for the cost of constructing the facility. The basis of the $1,000,000 facility is zero because the expected contributions equal the cost of the facility.

Pursuant to Section 367.171, F.S., on September 27, 1994, the Board of County Commissioners of Charlotte County adopted a resolution giving this Commission jurisdiction over privately owned water and wastewater utilities in Charlotte County. By Order No. PSC-94-1451-FOF-WS, issued November 28, 1994, the Commission acknowledged the County's resolution. By Order No. PSC-95-0478-FOF-SU, the Commission approved a grandfather certificate for the utility and approved the $1,250 plant capacity charge that Charlotte County had initially set. By Order No. PSC-99-2114-PAA-SU, the Commission approved the transfer from Sandalhaven Utility, Inc. to Utilities, Inc. of Sandalhaven and approved the adoption of the same $1,250 plant capacity charge.

Additionally, the amount of ADITs associated with the tax years 2001, 2002, and 2003, addressed by the PriceWaterhouseCoopers memorandum discussed above, have been retired in conjunction with the retirement of the WWTP and should be removed from the ADIT balance in any case. Further, in its response to staff's fifth data request number 12, Sandalhaven stated that the plant capacity fees that comprise the CIAC in question were misclassified as tap fees and are capacity charges.

In light of the above, staff believes that the debit ADITs from taxes paid on plant capacity charges should be disallowed for ratemaking purposes. This same issue was addressed in the utility's last case before the Commission in Docket No. 060285-WS, and in that case, the Commission disallowed the inclusion of the debit ADITs.[7]

Sandalhaven also included a debit ADIT amount of $137,165 associated with a NOL incurred in prior years. For the purpose of setting rates, staff believes the debit amount associated with the NOL should not be included in the ADIT balance unless the NOL is included in the calculation of the per book income tax expense. Including the debit ADIT for a NOL in years outside of the test year would allow the utility to recover prior year losses in current rates. Because the utility did not include the NOL in its income tax expense for the test year, staff recommends the debit amount of $137,165 be removed from the utility's ADIT balance. This treatment is consistent with the Commission's decision in the Labrador rate case in Docket No. 140135-WS.[8]

Based on staff's analysis above, the debit ADIT balance of $618,138 associated with plant capacity fees and the debit ADIT balance of $137,165 associated with the NOL should be disallowed. The resulting adjustment is an increase of $755,303 to the credit balance. Additionally, as discussed in Issue 4, a credit of $371 should be added to the ADIT balance to reflect the appropriate amount associated with the utility's requested pro forma plant additions. Accordingly, staff recommends that the appropriate 2014 average net used and useful credit ADITs balance to include in the capital structure is $214,874. This represents an increase of $755,674 to the credit balance, because the utility reflected a net debit balance in rate base of $540,800 in its revised MFRs.

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[7] Order No. PSC-07-0865-PAA-WS, issued October 29, 2007, in Docket No. 060285-WS, *In re: Application for increase in wastewater rates in Charlotte County by Utilities, Inc. of Sandalhaven, pages 23-26.*
[8] Order No. PSC-15-0208-PAA-WS, issued May 26, 2015, in Docket No. 140135-WS, *In re: Application for increase in water and wastewater rates in Pasco County by Labrador Utilities, Inc., pages 14-15.*

Issue 10: What is the appropriate weighted average cost of capital including the proper components, amounts, and cost rates associated with the capital structure for the test year ended December 31, 2014?

Recommendation: The appropriate weighted average cost of capital is 7.92 percent. (D. Buys)

Staff Analysis: In its filing, the utility requested an overall cost of capital of 8.50 percent. In addition to the recommendations discussed in Issues 8 and 9, staff believes the cost rate for short-term debt should be adjusted.

In its filing, Sandalhaven properly used the simple average method as required by Rule 25-30.433(4), F.A.C., to calculate a short-term interest rate of 7.77 percent. Using the simple average method, Sandalhaven calculated its average short-term debt balance to be $4,000,000. The utility's annual interest expense was $310,713. Dividing the annual interest expense by the simple average balance yields a short-term debt cost rate of 7.77 percent. The 13-month average short-term debt balance for the test year ended December 31, 2014, was $13,923,077. Using the 13-month balance instead of the simple average balance results in a short-term debt cost rate of 2.23 percent.

Using the simple average method yields an interest rate that is not reflective of the utility's actual cost of short-term debt. The short-term debt for Sandalhaven is allocated from its parent company, Utilities, Inc. The outstanding balance of short-term debt as of December 31, 2013, was $5,700,000 and the outstanding balance as of December 31, 2014, was $2,300,000. The simple average is $4,000,000. The average outstanding balance for the eleven months January 2014 through November 2014 was $15,727,273. Utilities, Inc. paid interest expense based on the larger outstanding balance, not the simple average balance of $4,000,000. Using the interest expense for a larger outstanding balance yields a cost rate that is artificially inflated for rate-making purposes and is unreasonable.

In its response to staff's fifth data request, number 14, the utility explained short-term debt increased throughout 2014 to temporarily cover long-term debt interest obligations and was reduced at year end through an infusion of equity by Sandalhaven's parent company, Utilities, Inc. While Utilities, Inc.'s short-term debt financial policies are fiscally prudent, Sandalhaven's customers should not pay a short-term debt cost rate that is not reflective of the actual cost of short-term debt incurred.

Labrador Utilities, Inc. (Labrador) used a simple average method to calculate the short-term debt cost rate.[9] In that docket, the Commission reduced the short-term debt cost rate to match that of Sanlando Utilities Corp. (Sanlando). Sanlando used a 13-month average method to calculate a short-term debt cost rate of 2.82 percent. In the Labrador docket, the Commission reasoned that given that both utilities (Labrador and Sanlando) had the same amount of interest expense, the simple average method skews the calculation of the cost rate. The Commission found that because the short-term debt for both utilities was allocated from their parent company, Utilities

[9] Id.

Inc., it was appropriate for the short-term debt cost rate to be the same and reduced Labrador's short-term debt cost rate to be the same as the rate for Sanlando.[10]

Consistent with the Commission's decision in the Labrador docket, staff recommends that the cost rate for short-term debt be calculated using a 13-month average method instead of a simple average method. Accordingly, staff recommends that the appropriate cost rate for short-term debt is 2.23 percent.

Based upon the proper components, amounts, and cost rates associated with the capital structure, staff recommends a weighted average cost of capital for the test year ended December 31, 2014, of 7.92 percent.

[10] Id

Issue 11: What are the appropriate test year revenues for the Utility's wastewater system?

Recommendation: The appropriate test year revenues for Sandalhaven's wastewater system, including miscellaneous revenues are $666,122. (Bruce)

Staff Analysis: As shown in Issue 2, the utility agreed to Audit Finding No. 6, which reflected a decrease in test year revenues of $17,939. However, after further analysis, staff discovered that additional billing determinants should be added to reflect the appropriate number of customers who paid guaranteed revenues. As a result, test year revenues should be increased by $2,285. Based on the above, the appropriate test year revenues for Sandalhaven's wastewater system, including miscellaneous revenues are $666,122.

Issue 12: Should any adjustment be made to the utility's salaries and wages expense?

Recommendation: Yes. Salaries and wages expense should be decreased by $67,362. Employee Pensions and Benefit expense should be decreased by $897. In addition, payroll tax expense should be decreased by $4,027. (Archer, D. Buys)

Staff Analysis: In its MFR, the utility recorded a Salaries & Wages expense of $149,373 and Employees Pensions and Benefits expense of $22,907. In the Affiliate Audit for UI, the staff auditors examined O&M expense allocations for Sandalhaven. In Audit Finding Number 3, audit staff reduced the salaries of officers and employees by $10,131, payroll taxes by $10 and benefits by $379. Included in the salary expense were five wastewater plant operators that equated to 2.275 FTEs. Staff agrees with the audit findings, however, further adjustments should be made.

Audit findings suggest that 1.2 full time equivalents (FTEs) for wastewater plant operators are necessary to continue operations on the wastewater system after the decommissioning of the WWTP. Further, in its response to staff's second data request number 2, the utility agreed that 1.2 FTEs should be sufficient on a going forward basis. Staff's analysis in this docket reviewed this expense in light of current duties and responsibilities as well as the utility's change in operations due to the decommissioning of the WWTP. Staff recommends a decrease in operators' salaries and benefits of $45,778 and $13,284, respectively, to reflect the reduction in operator FTEs. An additional adjustment should be made to decrease payroll taxes by $3,947.

Audit staff requested that the utility provide support for each employee, their most current annualized salary and the allocated salary, benefits, and taxes using the ERC allocation factor based on the employee's duties. The utility provided schedules using the salaries as of the end of April 2015 with the overtime earned in 2014, and the ERC factors at the end of April 2015. Some employees' aggregate salary was then increased by an average of 3 percent in preparation for the 2016 expenses. Consistent with prior Commission practice, staff believes that the increase for 2016 represents a pro forma expense that is outside of the test year and should be disallowed. Therefore, staff reduced non-operators' salaries, benefits and payroll taxes, by 3 percent.

In its MFRs the utility inadvertently made an adjustment to increase Salaries and Wages – Officers by $12,961. The adjusted amounts requested in the utility's MFRs are $22,907 for Pensions and Benefits, and $17,681 for Salaries and Wages – Officers. The staff audit findings reflected a balance of $35,489 for Pensions and Benefits and a balance of $13,948 for Salaries and Wages – Officers. Based on the audit findings, staff believes the utility's adjustment should have been made to Employees Pensions and Benefits expense.

Based on the audit findings and staff's analysis above, staff believes the appropriate amount of Salaries and Wages – Employees, Salaries and Wages – Officers, and Employee Pensions and Benefits is $68,481, $13,530, and $22,010, respectively. The appropriate amount for payroll taxes is $7,332. Staff's recommended adjustments are summarized in Table 12-1 below.

Table 12-1
Summary of Staff Recommended Adjustments

Expense	MFR Amount	Staff Adjustment	Recommended Final Amount
Employees	$131,692	($63,211)	$68,481
Officers	$17,681	($4,151)	$13,530
Total Salary	$149,373	($67,362)	$82,011
Benefits	$22,907	($897)	$22,010
Payroll Taxes	$11,359	($4,027)	$7,332

Source: MFRs and staff audit work papers

In conclusion, staff recommends that salaries and wages expense should be decreased by $67,362. Employee Pensions and Benefit expense should be decreased by $897, and payroll tax expense should be decreased by $4,027.

Issue 13: Should further adjustments be made to the utility's O&M expense?

Recommendation: Yes. O&M expense should be decreased by $83,287. (Archer, D. Buys)

Staff Analysis: Based on its review of test year O&M expense, staff recommends several adjustments to the utility's O&M expense as summarized below.

Purchased Sewage Treatment

In its MFRs, Sandalhaven reflected an expense of $338,874 for purchased sewage treatment. In response to a staff data request, the utility indicated that the pro forma adjustment of $166,911 to increase the expense was calculated in error and the increase should be $208,262, or an additional increase of $38,664. The increase is based on the number of gallons that will be treated by EWD due to the diversion of wastewater from the decommissioned WWTP to EWD, plus a growth allowance.

Staff disagrees with the utility's recalculated pro forma amount and recommends an additional pro forma increase of $22,447. Staff does not believe it is appropriate for the utility to include an allowance for growth in its calculation since O&M expenses should be based on costs incurred during the test year. The appropriate amount of purchased sewage treatment is $361,321. Staff based its estimate on the total number of gallons treated for the test year as reflected in MFR Schedule F-2. Sandalhaven reported total flows for the WWTP and wastewater treated by EWD to be 49.632 million gallons. The cost of treatment is $7.28 per 1,000 gallons. Multiplying the number of gallons treated by the cost yields an expense of $361,321 (49,632 x $7.28).

Excessive I&I Adjustment

Rule 25-30.432, F.A.C., provides that in determining the amount of U&U plant, the Commission shall consider infiltration and inflow (I&I). Typically, infiltration results from groundwater entering a wastewater collection system through broken or defective pipes and joints; whereas, inflow results from water entering a wastewater collection system through manholes or lift stations. Engineering staff calculated an excessive I&I of 26.07 percent. Accordingly, adjustments should be made to reduce the expense for chemicals, purchased power, and purchased sewage treatment. As such, staff recommends that chemicals be decreased by $87, purchased power be decreased by $3,866, and purchased sewage treatment be decreased by $94,196. The total O&M adjustment for excessive I&I is a decrease of $98,149.

Sludge Hauling

In its filing, Sandalhaven included a test year expense of $14,490 for sludge hauling and reflected a pro forma adjustment to remove $12,000 related to the decommissioning of the WWTP. A balance of $2,490 was reflected as the test year adjusted balance. However, in its letter dated October 26, 2015, the Office of Public Counsel indicated it believes that the remaining balance of $2,490 should be removed. Staff recommends that the remaining balance should be removed because the utility did not support the remaining cost for sludge hauling expense related to the WWTP.

Bad Debt Expense

In its MFRs the utility included bad debt expense of $5,700. In the three previous annual reports for 2012, 2013, and 2014, Sandalhaven reported bad debt expense of $8,412, ($8,418), and $5,701, respectively. Based on a 3-year average, staff believes that $1,898 is the appropriate amount of bad debt expense to include in the test year ended December 31, 2014. This treatment is consistent with the Commission's decision in the Labrador rate case in Docket No. 140239-WS.[11] Accordingly, staff recommends that bad debt expense be decreased by $3,802.

Regulatory Commission Expense – Other

In its filing, Sandalhaven included $2,013 for regulatory expense other than rate case expense. Staffs audit work papers showed that part of the utility's allocated expenses included an expense of $70,669 from Deloitte Consulting LLP for services rendered from February 2, 2014, through May 5, 2014, for Utilities, Inc. expert witnesses. The allocated amount included in the test year expense is $1,293. This expense was part of the rate case expense in Docket No. 120161-WS. In that case, the Commission found, "that rate case expense shall be allocated to each UI Florida subsidiary based on the ratio of each subsidiary's ERCs to UI's total Florida ERCs as of December 31, 2013."[12] The Order specified that each subsidiary would be allowed to recover its allocated portion of rate case expense over four years, pursuant to Section 367.0816, wherein the rate case expense was allocated to Utilities, Inc. sister companies. Sandalhaven's portion of that rate case expense was determined to be $2,484 and is included in the amortization of rate case expense in this case. Accordingly, staff recommends that regulatory commission expense – other be decreased by $1,293.

Based on staff's analysis above, staff recommends that O&M expense should be decreased by $83,287.

[11] Order No. PSC-15-0208-PAA-WS, issued May 26, 2015, in Docket No. 140135-WS, *In re: Application for increase in water and wastewater rates in Pasco County by Labrador Utilities, Inc.*

[12] Order No. PSC-14-0521-FOF-WS, issued Sept. 30, 2014, in Docket 120161-WS, *In re: Analysis of Utilities, Inc.'s financial accounting and customer service computer system, p. 19.*

Issue 14: What is the appropriate amount of rate case expense?

Recommendation: The appropriate amount of rate case expense is $123,015. This expense should be recovered over four years for an annual expense of $30,754. Therefore, annual rate case expense should be decreased by $2,830 from the respective levels of expense included in the MFRs. (Yeazel, D. Buys)

Staff Analysis: In its MFRs, Sandalhaven requested $131,850 for current rate case expense. Staff requested an update of the actual rate case expense incurred, with supporting documentation, as well as the estimated amount to complete the case. On October 15, 2015, the Utility submitted its last revised estimate of rate case expense, through completion of the PAA process, which totaled $133,057. A breakdown of the utility's requested rate case expense is as follows:

Table 14-1
Initial and Revised Rate Case Expense

	MFR B-10 Estimated	Actual	Additional Estimated	Revised Total
Legal Fees	$57,000	$30,144	$10,060	$40,204
Accounting Consultant Fees	57,750	72,664	4,500	77,163
Engineering Consultant Fees	7,000	3,608	1,983	5,590
Filing Fee	4,000	0	4,000	4,000
WSC Travel	1,000	0	1,000	1,000
WSC FedEx/Misc.	100	0	100	100
Cust. Notices and Postage	5,000	0	5,000	5,000
Total	$131,850	$106,416	$26,643	$133,057

Source: MFR Schedule B-10, Responses to staff data request

Pursuant to Section 367.081(7), F.S., the Commission shall determine the reasonableness of rate case expense and shall disallow all rate case expense determined to be unreasonable. Staff has examined the requested actual expenses, supporting documentation, and estimated expenses as listed above for the current rate case. Based on its review, staff believes the following adjustments to Sandalhaven's rate case expense estimate are appropriate.

Legal Fees – Friedman & Friedman, P.A. (F&F)

The first adjustment to rate case expense relates to Sandalhaven's legal fees. In its MFRs, the utility included $57,000 in legal fees to complete the rate case. The utility provided supporting documentation detailing this expense through October 6, 2015. The actual fees and costs totaled $30,144 with an estimated $10,060 to complete the rate case, totaling $40,204.

F&F's actual expenses included the $2,000 filing fee. However, the utility also included $4,000 in its MFR Schedule B-10, under "Public Service Commission – Filing Fee." Staff has left the filing fee as part of the legal fees and will remove the entry elsewhere to avoid double recovery of this fee.

According to invoices, the law firm of F&F identified and billed the utility $360 related to the correction of MFR deficiencies. The Commission has previously disallowed rate case expense associated with correcting MFR deficiencies because of duplicate filing costs.[13] Consequently, staff recommends an adjustment to reduce F&F's actual legal fees by $360.

F&F's estimate to complete the rate case includes fees for 26.5 hours at $360/hr.[14] and additional costs totaling $520. Staff believes the full amount of the estimate to complete, $10,060, is reasonable. Accordingly, no adjustment is necessary.

Accounting Consultant Fees – Milian, Swain & Associates (MS&A)

The second adjustment relates to MS&A's actual and estimated fees of $77,163, which was comprised of $72,664 in actual costs and $4,500 in estimated fees to complete the rate case as of September 29, 2015. In regard to MS&A's actual expenses, staff reviewed the supporting documentation and found that approximately 460.5 hours were related to MFR preparation.

In regard to MS&A's actual expenses, staff reviewed the supporting documentation and identified 4.25 hours related to correcting deficiencies. As stated previously, the Commission has previously disallowed rate case expense associated with correcting MFR deficiencies because of duplicate filing costs. As such, staff believes that $563 (3.75 hrs. x $150/hr.) should be removed for C. Yapp and $100 (0.5 hr. x $200/hr.) be removed for D. Swain. Accordingly, staff recommends that MS&A's actual accounting consultant fees be reduced by $663 ($563 + $100).

In addition to the deficiency adjustments, staff also identified approximately 16.5 hours for "MFRs – schedules, review, etc.," dated June 5, 2015, that should be removed. According to documentation provided by MS&A, D. Swain performed a similar review exactly one week prior. Moreover, the utility's MFRs were officially submitted two days prior, on June 3. Staff believes the review that took place on June 5 is duplicative and 16.5 hours for D. Swain should be removed. As such, staff believes that $3,300 (16.5 hr. x $200/hr.) should be disallowed for D. Swain. Accordingly, staff recommends that MS&A's actual accounting consultant fees be reduced by $3,963 ($663 + $3,300).

MS&A estimates that a total of 28.75 hours are needed to complete the case. According to MS&A's summary, the consultant estimated the following:

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[13] Order Nos. PSC-05-0624-PAA-WS, issued June 7, 2005, in Docket No. 040450-WS, *In re: Application for rate increase in Martin County by Indiantown Company, Inc.;* and PSC-01-0326-FOF-SU, issued February 6, 2001, in Docket No. 991643-SU, *In re: Application for increase in wastewater rates in Seven Springs System in Pasco County by Aloha Utilities, Inc.*

[14] Beginning January 1, 2015, the hourly rate increased based upon the application of the Price Index since hourly rates were last adjusted. This results in a new hourly rate of $360.

Table 14-2
MS&A's Estimated Hours to Complete Case

Est. Hours	Activity
5.75	Provide support to client – Responses to Staff's Data Requests, including updates to Rate Case Expense.
2.5	Review Interim Order, test interim rates and consult with client.
11	Review audit, discuss issues with client
4.75	Review Staff recommendations, testing recommended revenue requirements and resulting rates, including suppression calculations, and discuss with client.
4.75	Review PAA Order, testing final approved revenue requirements and resulting final rates, including suppression calculations, and discuss with client.
28.75	**Total**

Source: Responses to staff data request

As represented above, staff believes that the estimated hours to complete the case should be sufficient to address any remaining tasks. They do not appear to be excessive or unreasonable and appear to follow closely with the hours approved for MS&A in several recent sister utility rate cases.[15] As such, no adjustment is necessary.

Engineering Consultant Fees – M&R Consultants

The utility included $7,000 in its MFRs for M&R Consultants to provide consulting services for engineering-related schedules and responses to staff's data requests. The utility provided support documentation detailing the actual expense through October 8, 2015. The actual fees and costs totaled $3,608 with an additional $1,983 estimated to complete the rate case. Staff believes $5,590 ($3,608+$1,983) for engineering consultant fees is reasonable and justified. Accordingly, no adjustment is necessary.

Filing Fee

The utility included $4,000 in its MFR Schedule B-10 for the filing fee. According to documentation provided by F&F, the actual filing fee of $2,000 was paid as part of the legal fees. Since the amount is already included in F&F's legal fees, staff removed $4,000 to avoid double recovery of this fee.

WSC Travel Expense

In its MFRs, Sandalhaven estimated $1,000 for travel expenses. The utility provided neither support documentation for this expense, nor a detailed estimate of the expense to completion. Furthermore, based on several previous UI rate cases, UI does not send a representative from its Illinois office to attend the Commission Conference for PAA rate cases. Therefore, staff recommends that $1,000 of rate case expense associated with WSC Travel Expense be removed.

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[15] Order No. PSC-15-0233-PAA-WS, issued June 3, 2015, in Docket No. 140060-WS, *In re: Application for increase in water and wastewater rates in Seminole County by Sanlando Utilities Company*; and PSC-15-0208-PAA-WS, issued May 26, 2015, in Docket No. 140135-WS, *In re: Application for increase in water/wastewater rates in Pasco County by Labrador Utilities, Inc.*

WSC FedEx Expense

The next adjustment to the requested rate case expense relates to WSC expenses for FedEx and other miscellaneous costs. The utility estimated $100 of FedEx and other miscellaneous costs in its initial filing. The utility did not provide support for any in-house FedEx expenses. Based on the lack of support documentation, staff recommends that FedEx rate case expense be removed.

Customer Notices and Postage

In its revised rate case expense schedule, Sandalhaven reflected estimated costs of $5,000 for customer noticing and postage. The utility is responsible for sending out four notices: the interim notice, the initial notice, customer meeting notice, and notice of the final rate increase.

The Commission has historically approved recovery of noticing and postage, despite the lack of support documentation, based on a standard methodology to estimate the total expense using the number of customers and the estimated per unit cost of envelopes, copies, and postage.[16] The estimated cost of postage for the combined interim and initial notice, customer notice, and the final notice is approximately $854 (835 customers x $0.341 pre-sorted rate x 3 notices), the cost of copies is approximately $919 (835 customers x $0.10 per copy x 11 total pages), and the cost of envelopes is approximately $125 (835 customers x $0.05 x 3 notices). Based on these components, staff believes the total cost for these notices and postage is $1,898 ($854.21 + $918.50 + 125.25). As such, rate case expense should be decreased by $3,102 ($1,898 - $5,000) to allow for adequate expenses related to mailing notices in accordance with Rule 25-22.0407, F.A.C.

Additional Rate Case Expense

In addition to the rate case expense provided by the utility, the Commission found in the Utilities, Inc., generic docket "that rate case expense associated with Docket No. 120161-WS shall be allocated to each UI Florida subsidiary based on the ratio of each subsidiary's ERCs to UI's total Florida ERCs as of December 31, 2013."[17] The Order specified that each subsidiary would be allowed to recover its allocated portion of rate case expense over four years, pursuant to Section 367.0816, F.S. Recovery of this expense should be included as a separate line item within rate case expense as part of each subsidiaries' next file and suspend rate case, limited proceeding, or staff-assisted rate case. Sandalhaven's portion of rate case expense from that docket is $2,484, or $621 on an annual basis.[18]

Conclusion

Based upon the adjustments discussed above, staff recommends that Sandalhaven's revised rate case expense of $133,057 be decreased by $10,042, to reflect staff's adjustments and the additional rate case expense allocated from Docket No. 120161-WS, for a total of $123,015. A breakdown of staff's recommended rate case expense is as follows:

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[16] Order No. PSC-14-0025-PAA-WS issued January 10, 2014, in Docket No. 120209-WS, *In re: Application for increase in water and wastewater rates in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida.*

[17] Order No. PSC-14-0521-FOF-WS, issued Sept. 30, 2014, in Docket 120161-WS, *In re: Analysis of Utilities, Inc.'s financial accounting and customer service computer system*, p. 19.

[18] Id.

Table 14-3
Staff Recommended Rate Case Expense

Description	MFR Estimated	Utility Revised Act.& Est.	Staff Adjustment	Recom. Total
Legal Fees	$57,000	$40,204	(360)	39,844
Accounting Consultant Fees	57,750	77,163	(3,963)	73,200
Engineering Consultant Fees	7,000	5,590	0	5,590
Filing Fee	4,000	4,000	(4,000)	0
WSC Travel	1,000	1,000	(1,000)	0
WSC FedEx/Misc.	100	100	(100)	0
Cust. Notices and Postage	5,000	5,000	(3,102)	1,898
Total	$131,850	$133,057	($12,525)	$120,531
Add'l RCE – Generic Dkt.	$2,484			$2,484
Total w/Add'l RCE	$134,334			$123,015

Source: MFR Schedule B-10, Responses to Staff Data Request

In its MFRs, the utility requested total rate case expense of $134,334. When amortized over four years, this represents an annual expense of $33,584. The recommended total rate case expense of $123,015 should be amortized over four years, pursuant to Section 367.081(6), F.S. This represents an annual expense of $30,754. Based on the above, staff recommends that annual rate case expense be decreased by $2,830.

Issue 15: Should any further adjustment be made to Taxes other than Income?

Recommendation: Yes. Property Taxes should be decreased by $7,460. (D. Buys)

Staff Analysis: Rule 25-30.433(5), F.A.C., states that property tax on non-used and useful plant. shall not be allowed. In Issue 2, land was increased by $10,000 pursuant to an audit adjustment. As indicated in the utility's MFRs, a used and useful adjustment of 46.54 percent was applied to the land balance of $157,000 to reflect the portion of land not used to provide service to customers. This same adjustment should be applied to the agreed upon audit adjustment to increase land by $10,000. In Issue 5, staff recommends a non-used and useful adjustment to reduce plant and land. Based on the used and useful adjustments discussed in Issue 5, property tax should be decreased by $8,724 to reflect the disallowed portion of plant. In its MFRs, the utility reflected an adjustment of $1,264 to decrease property taxes for the non-used and useful adjustment to land. Accordingly, staff recommends that property tax expense be decreased by $7,460.

Issue 16: What is the appropriate revenue requirement for the test year ended December 31, 2014?

Recommendation: Staff recommends the following revenue requirement be approved.

Test Year Revenue	$ Increase	Revenue Requirement	% Increase
$666,122	$626,375	$1,292,497	94.03%

(D. Buys)

Staff Analysis: In its filing, Sandalhaven requested revenue a requirement to generate annual revenue of $1,620,750. This requested revenue requirement represents a revenue increase of $939,514, or approximately 137.91 percent.

Consistent with staff's recommendations concerning rate base, cost of capital, and operating income issues, staff recommends approval of rates designed to generate a revenue requirement of $1,292,497. Staff's recommended revenue requirement of $1,292,497 is $626,375 greater than staff's adjusted test year revenue of $666,122 or an increase of 94.03 percent. Staff's recommended pre-repression revenue requirement will allow the utility the opportunity to recover its expenses and earn a 7.92 percent return on its investment in rate base.

Issue 17: What are the appropriate rate structures and rates for Sandalhaven's wastewater systems?

Recommendation: The recommended rate structures and monthly wastewater rates are shown on Schedule No. 4. 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. (Bruce)

Staff Analysis: Sandalhaven is located in Charlotte County and provides wastewater service only. Water service is supplied by Charlotte County. The utility serves 788 residential, four multi-residential, and 43 general service customers. The average water demand for the residential wastewater customers is 2,085 gallons. Currently, the utility's residential rate structure consists of a uniform base facility charge (BFC) for all meter sizes and a gallonage charge with an 8,000 gallon cap. General service and multi-residential customers are billed a BFC based on the water meter size and a gallonage charge that is 1.2 times higher than the residential gallonage charge.

Staff performed an analysis of the utility's billing data to evaluate various BFC cost recovery percentages and gallonage caps for the residential customers. The goal of the evaluation was to select the rate design parameters that: (1) produce the recommended revenue requirement; (2) equitably distribute cost recovery among the utility's customers; and (3) implement a gallonage cap that considers approximately the amount of water that may return to the wastewater system.

Typically, the Commission's practice is to allocate at least 50 percent of the wastewater revenue to the BFC due to the capital intensive nature of wastewater plants. However, staff believes it is appropriate to allocate 55 percent to the BFC because the customer base is seasonal and the utility purchases wastewater treatment from EWD. Therefore, staff recommends a BFC allocation of 55 percent. Furthermore, it is Commission practice to set the wastewater cap at approximately 80 percent of residential wastewater gallons sold. Based on staff's review of the billing analysis, 86 percent of the gallons are captured at the 6,000 gallon consumption level. For this reason, staff recommends that the gallonage cap for residential customers be reduced to 6,000 gallons. The wastewater gallonage cap recognizes that not all water is returned to the wastewater system. Staff also recommends that the general service gallonage charge be 1.2 times greater than the residential gallonage charge, which is consistent with Commission practice. It should also be noted that because the average water demand (2,085) is very low and is provided by a different entity, staff believes that any impact on water demand based on an increase in the wastewater rates of Sandalhaven would be de minimis. Therefore, staff does not recommend a repression adjustment.

In the utility's last rate case, staff evaluated whether it was appropriate to bill multi-residential customers based the number of units for each complex. The utility indicated that there was a significant increase in the number of multi-residential customers projected to be served coupled with the fact that there was no way to verify the number of units that were going to be constructed. Therefore, the Commission determined that it was appropriate for multi-residential customer to be charged the same rate structure as the general service class. In this case, staff also evaluated whether it is appropriate to go behind the meter to assess the demand the multi-residential customers place on the system instead of relying on factored ERCs by meter size. However, many of the multi-residential customers have pools and irrigation systems which have water demand that may not return to the wastewater system. Therefore, staff recommends that consistent with the prior Commission order, the rate structure for multi-residential customers remain unchanged.

Based on the above, staff recommends a continuation of the BFC and uniform gallonage charge rate structure for all customers, a BFC allocation based on 55 percent of the wastewater revenue requirement, a residential gallonage cap of 6,000 gallons, and a gallonage charge for general service customers that is 1.2 times the residential gallonage charge. Table 17-1 contains two alternative rate structures.

Table 17-1
Staff's Recommended and Alternative Wastewater Rate Structures and Rates

	RATES AT TIME OF FILING	STAFF RECOMMENDED PHASE I RATES (55% BFC)	ALTERNATIVE I (50% BFC)	ALTERNATIVE II (55% BFC)
Residential				
Base Facility Charge	$29.34	$50.31	$45.73	$50.31
Charge per 1,000 gallons				
8,000 gallon cap	$6.59	N/A	N/A	$15.25
6,000 gallon cap	N/A	$15.58	$17.31	N/A
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
2,000 Gallons	$42.52	$81.47	$80.35	$80.81
6,000 Gallons	$68.88	$143.79	$149.59	$141.81
8,000 Gallons	$82.06	$143.79	$149.59	$172.31

Source: MFRs and staff's calculations

Summary

The recommended rate structures and monthly wastewater rates are shown on Schedule No. 4. 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 18: In determining whether any portion of the interim water and wastewater revenue increase granted should be refunded, how should the refund be calculated, and what is the amount of the refund, if any?

Recommendation: The appropriate refund amount should be calculated by using the same data used to establish final rates, excluding rate case expense and other items not in effect during the interim period. The revised revenue requirements for the interim collection period should be compared to the amount of interim revenues granted. Based on this methodology, no refund is necessary. As a result, the corporate undertaking amount of $356,608 should be released. (D. Buys)

Staff Analysis: By Order No. PSC-15-0320-FOF-WS, the Commission authorized the collection of interim rates, and required the utility to hold $356,608 subject to refund pursuant to Section 367.082, F.S. According to Section 367.082, F.S., any refund should be calculated to reduce the rate of return of the utility during the pendency of the proceeding to the same level within the range of the newly authorized rate of return. Adjustments made in the rate case test period that do not relate to the period interim rates are in effect should be removed. Rate case expense is an example of an adjustment which is recovered only after final rates are established.

In this proceeding, the test period for establishment of interim and final rates is the 12-month period ended December 31, 2014. Sandalhaven's approved interim rates did not include any provision for pro forma operating expenses or plant. The interim increase was designed to allow recovery of actual interest costs, and the lower limit of the last authorized range of return on equity. To establish the proper refund amount, staff calculated revised interim revenue requirements utilizing the same data used to establish final rates. Rate case expense was excluded because this item is prospective in nature and did not occur during the interim collection period.

Using the principles discussed above, staff calculated an adjusted interim revenue requirement of $1,260,294 for wastewater. The adjusted wastewater interim revenue requirement of $1,260,294 is higher than the interim revenue requirement of $786,742 granted in the Interim Order. As a result, no refund is necessary. Based on the above, staff recommends that the corporate undertaking amount of $356,608 be released.

Issue 19: What is the appropriate amount by which rates should be reduced four years after the established effective date to reflect the removal of the amortized rate case expense as required by Section 367.0816, Florida Statutes?

Recommendation: The wastewater rates should be reduced as shown on Schedule No. 4 to remove rate case expense grossed-up for regulatory assessment fees (RAFs) and amortized over a four-year period effective immediately following the expiration of the four-year rate case expense recovery period, pursuant to Section 367.0816, F.S. Sandalhaven 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 respective rate reductions. 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. (Bruce, D. Buys)

Staff Analysis: Section 367.0816, F.S., requires that the rates be reduced immediately following the expiration of the four-year period by the amount of the rate case expense previously included in rates.

Current Docket Rate Case Amortization

The total reduction for the instant case is $32,203. 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. Using Sandalhaven's recommended revenue, expenses, capital structure and customer base, the reduction in revenue will result in the rate decreases as shown on Schedule No. 4.

Charlotte County Rate Case Amortization

In Sandalhaven's 2012 rate case before the Board of County Commissioners of Charlotte County, the amortized rate case expense was determined to be $37,384.[19] The utility included this amount in its balance of unamortized rate case expense in the current docket. The total reduction for the Charlotte County case, grossed up for RAFs, is $39,146. The rates for Charlotte County rate case went into effect on December 21, 2012, and pursuant to Section 367.0816, F.S., the rates should be reduced on December 20, 2016. The four year rate reduction from the Charlotte County case are shown on Schedule No.4.

Summary

The wastewater rates should be reduced as shown on Schedule No. 4 to remove rate case expense grossed-up for regulatory assessment fees (RAFs) and amortized over a four-year period effective immediately following the expiration of the four-year rate case expense recovery period, pursuant to Section 367.0816, F.S. Sandalhaven 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 respective rate reductions. If the utility files this reduction in conjunction with a price index or pass-through rate adjustment,

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[19] Resolution 2012-209 before the Board of County Commissioners of Charlotte County, Florida, adopted November 13, 2012, *In re: Application of Utilities, Inc. of Sandalhaven for in increase in wastewater rates and charges.*

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 20: What are the appropriate customer deposits for Sandalhaven's wastewater system?

Recommendation: The appropriate initial customer deposit for the residential wastewater customers should be $166 for all meter sizes. The initial customer deposits for all general service meter sizes should be two times the average estimated bill for wastewater. The approved customer deposits 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 charges until authorized to change them by the Commission in a subsequent proceeding. (Bruce)

Staff Analysis: Rule 25-30.311, F.A.C., contains the criteria for collecting, administering, and refunding customer deposits. Customer deposits are designed to minimize the exposure of bad debt expense for the utility and, ultimately, the general body of ratepayers. Historically, the Commission has set initial customer deposits equal to two times the average estimated bill.[20] Currently, the utility's existing initial deposit for residential and general service customers are two times the average estimated bills. Based on staff's recommended wastewater rates, the appropriate initial customer deposit should be $166 for all meter sizes to reflect an average residential customer bill for two months.

Staff recommends the appropriate initial customer deposit for the residential wastewater customers should be $166 for all meter sizes. The initial customer deposits for all general service meter sizes should be two times the average estimated bill for wastewater. The approved customer deposits 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 charges until authorized to change them by the Commission in a subsequent proceeding.

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[20]Order Nos. PSC-13-0611-PAA-WS, issued November 19, 2013, in Docket No. 130010-WS, *In re: Application for increase in water rates in Lee County and wastewater rates in Pasco County by Ni Florida, LLC.* and PSC-14-0016-TRF-WU, issued January 6, 2014, in Docket No. 130251-WU, *In re: Application for approval of miscellaneous service charges in Pasco County, by Crestridge Utility Corporation.*

Issue 21: Should Sandalhaven's guaranteed revenue charge be revised?

Recommendation: Yes. Sandalhaven's guaranteed revenue charge should be revised. Staff's recommended guaranteed revenue charge is $50.31. The approved charge should be effective on or after the stamped approval date of the tariff, pursuant to Rule 25-30.475, F.A.C. (Bruce, Hudson)

Staff Analysis: During the test year, 68 lot owners in the Eagles Preserve subdivision paid a guaranteed revenue charge. The charge was collected prior to the utility's acquisition of the system in 1999, and has continued since that time. At the time of filing, the utility's guaranteed revenue charge was $28.42. In its MFRs, Sandalhaven requested a guaranteed revenue charge of $67.92. According to the utility, the proposed guaranteed revenue charge is an across the board increase to its current rate.

Rule 25-30.515(9), F.A.C., defines a guaranteed revenue charge as a charge designed to cover the utility's costs including, but not limited to the cost of operation, maintenance, depreciation, and any taxes, and to provide a reasonable return to the utility for facilities, a portion of which may not be used or useful to the utility or its existing customers. The charge is designed to help the utility recover a portion of its cost from the time capacity is reserved until a customer begins to pay monthly service rates.

In prior Commission cases, guaranteed revenue charges have been based on a charge that is equal to the utility's approved base facility charge.[21] In the current case, the utility and staff included the customers paying guaranteed revenues in the billing determinants to develop the proposed and recommended rates. As result, staff recommends that the guaranteed revenue charge be equal to staff's recommended BFC for one ERC, which is $50.31.

In response to staff's data request, the utility indicated the customers who pay guaranteed revenues did not prepay the service availability charges. The Commission has found that guaranteed revenue charges lock in the amount of service availability charges notwithstanding a PSC approved change in service availability charges prior to the time of connection. Therefore, when those customers connect to the utility, the lot owners should pay the service availability charges that were in effect at the time capacity was reserved and guaranteed revenues began to be collected.[22] Those customers should not be required to pay the allowance for funds prudently invested charges (AFPI) because the guaranteed revenue charge has reimbursed the utility for the cost of operation, maintenance, depreciation, taxes, and return on investment for those customers share of the utility's facilities.

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[21] Order No. PSC-99-2114-PAA-SU, issued in October 25, 1999, in Docket No. 981221-SU, *In re: Application for transfer of Certificate No. 495-S in Charlotte County from Sandalhaven Utility, Inc. to Utilities, Inc. of Sandalhaven;* Order No. PSC-02-0658-PAA-SU, issued in May 14, 2002, in Docket Nos. 931111-SU and 991812-SU, *In re: Application for Certificate to operate wastewater utility in Franklin County by Resort Village Utility, Inc. and Application for transfer of Certificate No. 492-S in Franklin County from Resort Village Utility, Inc. to SGI Utility, LLC.*

[22] Order No. 16625, issued, September 23, 1986, in Docket No. 861771-WS, *In re: Petition of Edward Keohane for Declaratory Statement.*

Further, the guaranteed revenue charge is only applicable to the Eagles Preserve subdivision. Future customers requesting service will pay the utility's approved service availability and AFPI charges.

Based on the above, Sandalhaven's guaranteed revenue charge should be revised. Staff's recommended guaranteed revenue charge is \$50.31, consistent with staff's recommended base facility charge. The approved charge should be effective on or after the stamped approval date of the tariff, pursuant to Rule 25-30.475, F.A.C.

Issue 22: Should Sandalhaven's existing service availability policy and charges be revised, and if so, what is the appropriate policy and charges?

Recommendation: Yes. Staff recommends that the utility's existing main extension policy remain in effect and a plant capacity charge of $3,270 per ERC should be approved. The approved service availability charges should be effective for connections made on or after the stamped approval date of the tariff, pursuant to Rule 25-30.475, F.A.C. (Bruce, Hudson)

Staff Analysis: In Docket No. 060285-SU, the Commission approved a plant capacity charge of $2,628 per ERC and a main extension charge at actual cost. However, the tariff was inadvertently approved with the plant capacity charge described as a system capacity charge. As a result, subsequent to Charlotte County rescinding jurisdiction in 2007, the county approved the charge as a system capacity charge as well. In its rate case proceeding in 2012, Charlotte County did not revise the service availability charges approved by the Commission. When Charlotte County returned jurisdiction to the Commission in 2013, the Commission approved the utility's existing rates and charges, including the $2,628 charge which was described as a system capacity charge.

A system capacity charge is a single service availability charge that includes the cost of both plant and lines. For a utility that receives donated lines from a developer, an individual customer connecting to those lines should only be responsible for a service availability charge that reflects plant costs. Therefore, separate charges are typically developed to reflect the customer's share of plant costs (plant capacity charges) and the cost of lines in lieu of donated lines (main extension charges).

Rule 25-30.580, F.A.C., establishes guidelines for designing service availability charges. Pursuant to the rule, the maximum amount of contributions-in-aid-of-construction (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 designed capacity. The minimum amount CIAC should not be less than the percentage of such facilities and plant that is represented by the sewage collection systems. The utility's current contribution level is approximately 30 percent.

Main Extension Charge

The utility's existing collection system, which was contributed by developers, is designed to serve the existing customers as well as the property for which service availability charges have been prepaid (2,175 ERCs). The utility's service territory includes some vacant property as well as an area with septic tanks; service to customers in those areas would require the installation of additional collection lines.

The utility's existing service availability policy requires customers to either install and donate collection lines to the utility or reimburse the utility if the utility constructs the main extension. In the event the utility oversizes the line to accommodate future customers, the utility absorbs the incremental cost of the additional capacity and collects a pro rata share of the cost from subsequent customers. If a developer installs an oversized line in anticipation of future customers, the developer would be entitled to a refundable advance agreement such that, as future customers connect to the oversized line, the developer is reimbursed for that customer's share of the cost of the line. Therefore, a customer would not both construct and donate a collection line and pay a main extension charge.

Based on the above, staff recommends the main extension charge remain at actual cost. In addition, the utility's service availability policy should continue to require donated lines as described above, consistent with the guidelines in Rule 25-30.580, F.A.C., which require that, at a minimum, the cost of the utility's lines should be contributed.

Plant Capacity Charge

As previously discussed, all of Sandalhaven's wastewater flows are diverted through a force main interconnection with EWD. In addition, the utility has an agreement for purchased treatment capacity with the EWD. Therefore, the interconnection and purchased wastewater capacity from the EWD act as a surrogate wastewater treatment plant for Sandalhaven.

The cost of the force main included in rate base is $2,150,656 and it has capacity of 1,000,000 gpd. The utility paid $2,258,119 for the 300,000 gpd of purchased capacity from the EWD. In order to determine an appropriate plant capacity charge, staff calculated the cost of the interconnection and the purchased capacity on a gpd basis. The force main cost per gpd is $7.53 ($2,150,656/1,000,000) and the purchased capacity cost per gpd is $2.15 ($2,258,119/300,000). As described in Issue 5, the capacity of the force main is based on peak demand and the capacity purchased form EWD is based on average demand. Therefore, staff calculated a plant capacity charge that reflects the cost of the force main based on peak demand and the cost of the purchased capacity based on average demand. For this analysis, staff used an average demand of 190 gpd. Staff recommends a plant capacity charge of $3,270 per ERC (ERC equals 190 gpd).

Based on the above, staff recommends that the utility's existing main extension policy remain in effect and a plant capacity charge of $3,270 per ERC should be approved. The approved service availability charges should be effective for connections made on or after the stamped approval date of the tariff, pursuant to Rule 25-30.475, F.A.C.

Issue 23: Should Sandalhaven's existing Allowance for Funds Prudently Invested (AFPI) charges be revised, and if so, what are the appropriate charges?

Recommendation: Yes. Sandalhaven's existing AFPI charges should be revised. The beginning date of the new AFPI charges should be January 1, 2015. After December 31, 2020, the utility should be allowed to collect the constant charge until 792 future ERCs have been added, at which time the charge should be discontinued. The charge should be collected from future connection based upon the time of the initial connection. The revised tariff sheets should be approved upon staff's verification that the tariffs are consistent with the Commission's decision The approved AFPI charges should be effective for connections made on or after the stamped approval date of the tariff, pursuant to Rule 25-30.475, F.A.C. (Bruce, Hudson)

Staff Analysis: An AFPI charge is a mechanism designed to allow a utility the opportunity to earn a fair rate of return on prudently constructed plant held for future use from the customers that will be served by that plant. The charge is calculated based on the costs associated with the non-used and useful plant. This one-time charge is assessed based on the date the future customer pays the utility's approved service availability charges and connects to the utility.

The utility's existing AFPI charges, which were established by Charlotte County when the utility was under its jurisdiction, are based on purchased wastewater capacity from the EWD, interconnection costs of the force main, and the master lift station. The utility did not propose a change in its AFPI charges.

As discussed in Issue 2, staff is recommending that the purchased wastewater capacity and master lift station be considered 100 percent used and useful. Further, staff is recommending that the force main be considered 74.9 percent used and useful. Therefore, because only the force main has non-used and useful capacity in the current case, staff believes that it is appropriate to revise the utility's AFPI charges to reflect staff's recommended non-used and useful plant.

The test year used in this case for establishing the amount of non-used and useful plant is the year ended December 31, 2014. Pursuant to Rule 25-30.434(4), F.A.C., the beginning date for accruing the AFPI charge should agree with the month following the end of the test year that was used to establish the amount of non-used and useful plant. Therefore, the beginning date for the AFPI accrual in this case is January 1, 2015. Furthermore, in accordance with Rule 25-30.434(4), F.A.C., no charge may be collected for any connections made between the beginning dates and the effective date of the AFPI charges. Typically, an AFPI charge is calculated for a five-year period.

Based on the staff recommended non-used and useful portion of the force main and the associated ERCs, staff calculated the wastewater AFPI charges contained in Table 23-1 below.

Table 23-1
Allowance for Funds Prudently Invested
Calculation of Carrying Cost Per ERC Per Month

	2015	2016	2017	2018	2019
January	9.73	127.00	251.23	382.96	522.80
February	19.45	137.30	262.15	394.56	535.12
March	29.18	147.60	273.07	406.15	547.44
April	38.90	157.90	284.00	417.74	559.75
May	48.63	168.20	294.92	429.33	572.07
June	58.35	178.50	305.84	440.93	584.39
July	68.08	188.80	316.76	452.52	596.71
August	77.80	199.11	327.68	464.11	609.03
September	87.53	209.41	338.61	475.70	621.35
October	97.25	219.71	349.53	487.30	633.67
November	106.98	230.01	360.45	498.89	645.99
December	116.70	240.31	371.37	510.48	658.30

Source: Staff's calculations

Based on the above, staff recommends that Sandalhaven's existing AFPI charges should be revised. The beginning date of the new AFPI charges should be January 1, 2015. After December 31, 2020, the utility should be allowed to collect the constant charge until 792 future ERCs have been added, at which time the charge should be discontinued. The charge should be collected from future connection based upon the time of the initial connection. The revised tariff sheets should be approved upon staff's verification that the tariffs are consistent with the Commission's decision The approved AFPI charges should be effective for connections made on or after the stamped approval date of the tariff, pursuant to Rule 25-30.475, F.A.C.

Issue 24: Should the utility be required to provide proof, within 90 days of an effective order finalizing this docket, that it has adjusted its books for all the applicable National Association of Regulatory Utility Commissioners (NARUC) Uniform System of Accounts (USOA) associated with the Commission approved adjustments?

Recommendation: Yes. To ensure that the utility adjusts its books in accordance with the Commission's decision, Sandalhaven should notify the Commission in writing within 90 days of the final order in this docket that the adjustments to all the applicable NARUC USOA accounts have been made to the utility's books and records. (D. Buys)

Staff Analysis: To ensure that the utility adjusts its books in accordance with the Commission's decision, Sandalhaven should notify the Commission in writing within 90 days of the final order in this docket that the adjustments to all the applicable NARUC USOA accounts have been made to the utility's books and records.

Issue 25: 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. (Brownless)

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.

Utilities, Inc. of Sandalhaven
Schedule of Wastewater Rate Base
Test Year Ended 12/31/14

Schedule No. 1

Docket No. 150102-SU

	Description	Test Year Per Utility	Utility Adjust-ments	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year
1	Plant in Service	$8,571,371	($181,463)	$8,389,908	($210,419)	$8,179,489
2	Land and Land Rights	157,487	209	157,696	10,000	167,696
3	Non-used and Useful Components	0	(73,089)	(73,089)	(494,940)	(568,029)
4	Accumulated Depreciation	(3,712,738)	773,864	(2,938,874)	332,017	(2,606,857)
5	CIAC	(3,276,640)	1,310,499	(1,966,141)	(258,674)	(2,224,815)
6	Amortization of CIAC	1,595,021	(1,071,361)	523,660	19,536	543,196
7	Construction Work in Progress	134,200	(134,200)	0	0	0
8	Working Capital Allowance	0	87,257	87,257	(16,610)	70,647
9	Debit ADITs	0	540,800	540,800	(540,800)	0
10	**Rate Base**	$3,468,701	$1,252,516	$4,721,217	($1,159,890)	$3,561,327

Utilities, Inc. of Sandalhaven
Adjustments to Rate Base
Test Year Ended 12/31/14

Schedule No. 1-A
Docket No. 150102-SU

	Explanation	Wastewater
	Plant In Service	
1	Reflect agreed upon audit adjustments (Issue 2)	($33,211)
2	Reflect appropriate plant retirement (Issue 3)	($23,335)
3	Reflect appropriate pro forma plant (Issue 4)	($153,873)
	Total	($210,419)
	Land	
	Reflect agreed upon audit adjustments (Issue 2)	$10,000
	Non-used and Useful	
1	Reflect non-used and useful adjustment to land (Issue 5)	($4,662)
2	Reflect net non-used & useful adjustment for Force Main (Issue 5)	($490,278)
	Total	($494,940)
	Accumulated Depreciation	
1	Reflect agreed upon audit adjustments (Issue 2)	$29,974
2	Reflect appropriate adjustment for retirement of WWTP (Issue 3)	$297,173
3	Reflect appropriate amount for pro forma plant adjustment (Issue 4)	$4,870
	Total	$332,017
	CIAC	
	Reflect appropriate amount for retirement of WWTP (Issue 3)	($258,674)
	Accumulated Amortization of CIAC	
	Reflect appropriate amount for retirement of WWTP (Issue 3)	$19,536
	Working Capital	
	To reflect the appropriate working capital allowance (Issue 6)	($16,610)

Utilities, Inc. of Sandalhaven
Capital Structure-Simple Average
Test Year Ended 12/31/14

Schedule No. 2
Docket No. 150102-SU

	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	$180,000,000	$0	$180,000,000	($177,683,994)	$2,316,006	49.06%	6.64%	3.26%
2	Short-term Debt	$4,000,000	$0	$4,000,000	($3,948,533)	$51,467	1.09%	7.77%	0.08%
3	Preferred Stock	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%
4	Common Equity	$182,354,550	$0	$182,354,550	($180,008,249)	$2,346,301	49.70%	10.37%	5.15%
5	Customer Deposits	$6,591	$0	$6,591	$0	$6,591	0.14%	2.00%	0.00%
6	Deferred Income Taxes	$0	$852	$852	$0	$852	0.02%	0.00%	0.00%
7	**Total Capital**	$366,361,141	$852	$366,361,993	($361,640,776)	$4,721,217	100.00%		8.50%
Per Staff									
8	Long-term Debt	$180,000,000	$0	$180,000,000	($178,359,034)	$1,640,966	46.08%	6.64%	3.06%
9	Short-term Debt	$4,000,000	$0	$4,000,000	($3,963,534)	$36,466	1.02%	2.23%	0.02%
10	Preferred Stock	$0	$0	$0	$0	$0	0.00%	0.00%	0.00%
11	Common Equity	$182,354,550	$0	$182,354,550	($180,692,119)	$1,662,431	46.68%	10.36%	4.84%
12	Customer Deposits	$6,591	$0	$6,591	$0	$6,591	0.19%	2.00%	0.00%
13	Deferred Income Taxes	$0	$214,874	$214,874	$0	$214,874	6.03%	0.00%	0.00%
14	**Total Capital**	$366,361,141	$214,874	$366,576,015	($363,014,688)	$3,561,327	100.00%		7.92%

	LOW	HIGH
RETURN ON EQUITY	9.36%	11.36%
OVERALL RATE OF RETURN	7.46%	8.39%

Utilities, Inc. of Sandalhaven
Statement of Wastewater Operations
Test Year Ended 12/31/14

Schedule No. 3
Docket No. 150102-SU

	Description	Test Year Per Utility	Utility Adjust-ments	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year	Revenue Increase	Revenue Requirement
1	**Operating Revenues:**	$668,757	$951,993	$1,620,750	($954,628)	$666,122	$626,375	$1,292,497
							94.03%	
	Operating Expenses							
2	Operation & Maintenance	$581,100	$116,957	$698,057	($132,877)	$565,180	$0	$565,180
3	Depreciation	264,739	(71,698)	193,041	(5,558)	187,483	0	187,483
4	Amortization	0	10,412	10,412	(642)	9,770	0	9,770
5	Taxes Other Than Income	113,952	57,013	170,965	(55,253)	115,712	28,187	143,899
6	Income Taxes	(118,083)	265,055	146,972	(268,114)	(121,142)	225,098	103,956
7	**Total Operating Expense**	841,708	377,739	1,219,447	(462,443)	757,004	253,285	1,010,288
8	**Operating Income**	($172,951)	$574,254	$401,303	($492,185)	($90,882)	$373,090	$282,208
9	**Rate Base**	$3,468,701		$4,721,217		$3,561,327		$3,561,327
10	**Rate of Return**	-4.99%		8.50%		-2.52%		7.92%

Utilities, Inc. of Sandalhaven
Adjustment to Operating Income
Test Year Ended 12/31/14

Schedule No. 3-A
Docket No. 150102-SU

	Explanation	Wastewater
	Operating Revenues	
1	Remove requested final revenue increase	($939,514)
2	Reflect appropriate test year revenue	2,825
3	Reflect agreed upon audit adjustments (Issue 2)	(17,939)
	Total	($954,628)
	Operation and Maintenance Expense	
1	Reflect agreed upon audit adjustments (Issue 2)	$21,499
2	Reflect the appropriate Salaries & Wages expense (Issue 12)	(67,362)
3	Reflect the appropriate Employee Pensions & Benefits Expense (Issue 12)	(897)
4	Reflect the appropriate amount for purchased sewage treatment (Issue 13)	22,447
5	Excessive I&I adjustment (Issue 13)	(98,149)
6	Reflect the appropriate sludge hauling expense (Issue 13)	(2,490)
7	Reflect the appropriate amount of Bad Debt Expense (Issue 13)	(3,802)
8	Reflect the appropriate amount of regulatory expense – other (Issue 13)	(1,293)
9	Reflect the appropriate rate case expense (Issue 14)	(2,830)
	Total	($132,877)
	Depreciation Expense - Net	
1	Reflect agreed upon audit adjustments (Issue 2)	$18,603
2	Reflect appropriate adjustment for WWTP retirement (Issue 3)	6,160
3	Reflect depreciation expense on pro forma plant adjustment (Issue 4)	(4,870)
4	Remove net depreciation on non-U&U adjustment (Issue 5)	(25,451)
	Total	($5,558)
	Amortization-Other Expense	
	Reflect appropriate net loss related to retirement of WWTP (Issue 3)	($642)
	Taxes Other Than Income	
1	RAFs on revenue adjustments above.	($42,958)
2	Reflect agreed upon audit adjustments (Issue 2)	(807)
3	Reflect appropriate property taxes related to U&U adjustment (Issue 5)	(7,460)
4	Reflect appropriate payroll taxes (Issue 15)	(4,027)
	Total	($55,253)

UTILITIES, INC. OF SANDALHAVEN
DOCKET NO. 150102-SU
MONTHLY WASTEWATER RATES

SCHEDULE NO. 4
DOCKET NO. 150102-SU

	RATES AT TIME OF FILING	COMMISSION APPROVED INTERIM RATES	UTILITY REQUESTED RATES	STAFF RECOMMENDED RATES	CHARLOTTE COUNTY 4 YEAR RATE REDUCTION	STAFF RECOMMENDED 4 YEAR RATE REDUCTION	10 YEAR WWTP DECOMMISSIONING REDUCTION
Residential							
Base Facility Charge - All Meter Sizes	$29.34	$34.60	$70.12	$50.31	$1.39	$1.26	$0.40
Charge per 1,000 Gallons - Residential							
8,000 gallon cap	$6.59	$7.77	$15.75				
6,000 gallon cap				$15.58	$0.43	$0.39	$0.12
General Service							
Base Facility Charge by Meter Size							
5/8"X3/4"	$29.34	$34.60	$70.12	$50.31	$1.39	$1.26	$0.40
1"	$73.35	$86.50	$175.31	$125.78	$3.48	$3.14	$0.99
1-1/2"	$146.69	$173.00	$350.59	$251.55	$6.95	$6.29	$1.99
2"	$234.71	$276.80	$560.96	$402.48	$11.12	$10.06	$3.18
3"	$469.43	$553.60	$1,121.94	$804.96	$22.24	$20.12	$6.36
4"	$733.47	$865.00	$1,752.99	$1,257.75	$34.75	$31.44	$9.94
6"	$1,466.94	$1,730.00	$3,505.99	$2,515.50	$69.50	$62.89	$19.87
Charge per 1,000 Gallons - General Service	$7.92	$9.34	$18.93	$18.70	$0.52	$0.47	$0.15
Typical Residential 5/8" x 3/4" Meter Bill Comparison							
2,000 Gallons	$42.52	$50.14	$101.62	$81.47			
6,000 Gallons	$68.88	$81.22	$164.62	$143.79			
8,000 Gallons	$82.06	$96.76	$196.12	$143.79			

Item 20

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: November 18, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Harlow, Lingo, Margolis, Shafer)
Office of the General Counsel (Tan)

RE: Docket No. 140226-EI – Request to opt-out of cost recovery for investor-owned electric utility energy efficiency programs by Wal-Mart Stores East, LP and Sam's East, Inc. and Florida Industrial Power Users Group.

AGENDA: 12/3/15 – Regular Agenda – Post-Hearing Decision – Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: Graham, Edgar, Brown

PREHEARING OFFICER: Graham

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: Staff recommends that the Commission take up Issue 2 first as the threshold issue, followed by Issue 3, then Issue 1, and finally, Issue 4.

Case Background

The Commission opened this docket to address issues raised by Wal-Mart Stores East, LP and Sam's East, Inc. (Wal-Mart) and Florida Industrial Power Users Group (FIPUG).[1] During the October 8, 2014 Prehearing Conference in Docket No. 140002-EG, the Energy Conservation Cost Recovery (ECCR) clause docket, Wal-Mart and FIPUG (hereafter referred to as the petitioners) proposed issues that addressed allowing certain large commercial and industrial customers the option of opting out of participating in investor-owned utility-sponsored energy efficiency programs. In return, customers that choose to opt out would not be charged the costs

[1] Order No. PSC-14-0583-PHO-EG, issued October 15, 2014, in Docket No. 140002-EG, In Re: Energy Conservation Cost Recovery Clause.

State of Florida

Public Service Commission

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

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The Prehearing Officer, however, ruled that the proposed issues should be considered in a separate docket. Consequently, the current docket was opened to address the three issues proposed by Wal-Mart and FIPUG. The petitioners represent large commercial or industrial customers.

The five investor-owned utilities (IOUs) subject to the Florida Energy Efficiency and Conservation Act (FEECA) may seek to recover costs associated with Commission-approved demand-side management (DSM) programs through the ECCR clause. These utilities are: Duke Energy Florida, LLC (DEF), Florida Power & Light Company (FPL), Florida Public Utilities Company (FPUC), Gulf Power Company (Gulf), and Tampa Electric Company (TECO).

The Commission granted intervention to the Southern Alliance for Clean Energy (SACE) and White Springs Agricultural Chemicals, Inc. (PCS Phosphate or PCS).[2] [3] The Commission also acknowledged intervention by the Office of the Public Counsel (OPC).[4]

The Commission has jurisdiction over this matter pursuant to Sections 366.80 through 366.83 and 403.519, Florida Statutes (F.S.), collectively known as FEECA.

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[1] Order No. PSC-14-0583-PHO-EG, issued October 15, 2014, in Docket No. 140002-EG, In Re: Energy Conservation Cost Recovery Clause.

[2] Order No. PSC-15-0201-PCO-EI, issued May 19, 2015, in Docket No. 140226-EI, In re: Request to opt-out of cost recovery for investor-owned electric utility energy efficiency programs by Wal-Mart Stores East, LP and Sam's East, Inc. and Florida Industrial Power Users Group.

[3] Order No. PSC-15-0247-PCO-EI, issued June 12, 2015, in Docket No. 140226-EI, In re: Request to opt-out of cost recovery for investor-owned electric utility energy efficiency programs by Wal-Mart Stores East, LP and Sam's East, Inc. and Florida Industrial Power Users Group.

[4] Order No. PSC-15-0213-PCO-EI, issued May 29, 2015, in Docket No. 140226-EI, In re: Request to opt-out of cost recovery for investor-owned electric utility energy efficiency programs by Wal-Mart Stores East, LP and Sam's East, Inc. and Florida Industrial Power Users Group.

Staff suggests that the Commission first proceed to Issue 2 which is the threshold issue of whether and opt-provision should be approved. Staff then suggests addressing Issue 3 which addresses implementation details necessary for an opt-out program, followed by Issues 1 and 4.

Discussion of Issues

Issue 1: Should the Commission require the utilities to separate their Energy Conservation Cost Recovery expenditures into two categories, one for Energy Efficiency programs and the other for Demand-Side Management programs?

Primary Recommendation: The petitioners have suggested separating the costs in the Energy Conservation Cost Recovery (ECCR) clause as a means of implementing the proposed opt-out provision. If the Commission approves staff's primary recommendation in Issue 2 to deny the petitioners' request, then no changes to current ECCR clause practices are necessary. (Lingo, Margolis, Harlow)

Alternative Recommendation: If the Commission approves alternative staff's recommendation in Issue 2, the four largest IOUs will be required to develop a pilot opt-out program. Implementing the pilot program would require the IOUs to determine the proportion of total ECCR costs related to energy efficiency programs paid by each customer that chooses to participate in the pilot. Alternative staff recommends that the appropriate methodology for determining the category and level of costs from which opt-out customers are seeking relief should be subject to discussion among the parties at a workshop as recommended in Issues 2 and 3. (Shafer)

Position of the Parties:

FIPUG: Yes, the Commission should take appropriate administrative steps, as Commissions across the country have, to implement an opt-out program in Florida.

Wal-Mart: Yes.

PCS: Yes. PCS agrees with FIPUG and Wal-Mart that this separation should be implemented.

FPL: No. Programs that pass the RIM test benefit the general body of customers, including non-participating customers, regardless of their characterization as energy efficiency or demand reduction/load management. Accordingly, distinguishing between the two would not provide a meaningful basis for determining costs that opt-out customers would be allowed to avoid.

DEF: No, separating expenditures in this way is not necessary. However, if the Commission intends to implement an opt-out policy that only applies to Energy Efficiency programs, DEF would be able to separate the charges with little difficulty.

TECO: No. The Commission should not require such a separation of expenditures into two categories. All of Tampa Electric's approved DSM measures provide demand and energy savings. Energy efficiency programs clearly provide both energy savings and demand reductions.

Gulf: No. Virtually all of Gulf Power's programs provide both energy and demand savings. The opt-out proponents correctly recognize the benefits of implementing demand response programs but fail to recognize that cost-effective energy efficiency programs also provide benefits to participating and non-participating customers alike.

FPUC: No.

SACE: No, not at this time.

OPC: Since the Proponents' opt-out proposals do not appear to clearly and convincingly establish that they meet, at a minimum, the Commission's approved cost-effectiveness test, RIM, there appears to be an insufficient basis for the Commission to consider separating the ECCR expenditures into separate categories for Energy Efficiency and Demand Side Management programs.

Staff Analysis:

Background and Positions of the Parties

Costs for all types of investor-owned utility-sponsored conservation programs are currently recovered from all ratepayers through the Energy Conservation Cost Recovery clause (ECCR). In order to facilitate an opt-out provision, FIPUG, Wal-Mart, and PCS Phosphate advocate separating the costs recovered through the ECCR clause into costs associated with energy efficiency programs and costs associated with demand response programs. (TR 50-52, 118, 506-507)

Wal-Mart witnesses Baker and Chriss, along with FIPUG witness Pollock and PCS, all agree that the utilities should be required to separate their ECCR expenditures into two categories, one for energy efficiency programs and the other for demand-side management (also referred to as demand response) programs. Under witness Baker's proposal, the non-residential customers who implement their own energy efficiency programs and meet certain other criteria to opt out of the utility's energy efficiency programs should not be required to pay the cost recovery charges for the utility's energy efficiency programs. (TR 50-52) In general, witness Chriss proposes that, for the customer classes that would be eligible to opt out, the ECCR rates be split into two components: (1) ECCR "Part E," for energy efficiency program-related costs and (2) ECCR "Part D," for demand response program-related costs. Witness Chriss notes that under witness Baker's proposal, eligible customers who opt out would be exempted from paying Part E, but would continue to pay Part D. (TR 118)

Witness Baker testified that the Florida investor-owned utilities' ECCR charges should be redesigned such that the energy efficiency charges are segregated from the demand-side management portion of the ECCR charge. (TR 46) The utilities should be required to separate their ECCR expenditures into two categories: (1) efficiency programs; and (2) demand-side management programs. (TR 50) Witness Baker also testified that by virtue of their self-implemented measures, such customers would be exempt from paying the ECCR charges for the energy efficiency portion of the charge, and that they would correspondingly be excluded from participation in the utilities' energy efficiency programs and measures. Through testimony by witness Baker, Wal-Mart stated that these recommendations would apply to the four largest investor-owned utilities, Florida Power & Light, Duke Energy Florida, Tampa Electric Company, and Gulf Power Company. (TR 46) In response to staff interrogatories, however, Wal-Mart indicated that the proposal could apply to Florida Public Utilities as well. (EXH 22, Bates 35) FIPUG states that to the extent Florida Public Utilities has customers who would be eligible; they should be able to participate. (EXH 22, Bates 19)

Witness Chriss testified regarding the ratemaking treatment for witness Baker's proposal for a large customer electing to opt out of the energy efficiency portion of each utility's ECCR rates. In summary, witness Chriss' recommendations are:

1. For those customer classes that would be eligible to opt out under witness Baker's proposal, Wal-Mart proposes that the ECCR rates be split into two components: (1) ECCR "Part E," for energy program-related costs and (2) ECCR "Part D," for demand response program-related costs.

2. For a given customer class or group of classes, the Part E rate would be calculated as the energy-related revenue requirement, allocated to the class or group of classes, divided by the applicable kWh or kW billing determinants for that class or group of classes. The Part D rate would then be calculated as the demand revenue requirement divided by the applicable kWh or kW billing determinants for that class or group of classes.

3. For the purposes of calculating the ECCR Part E and Part D rates, Wal-Mart does not oppose the use of each respective utility's approved classification of its energy conservation program costs into energy-related and demand-related components. (TR 115-116)

The IOUs unanimously disagree with the petitioners' request, providing testimony that allowing customers to opt out of the energy efficiency portion of each utility's ECCR rates is not necessary because the utility-sponsored programs that pass the RIM test, including both demand response and energy efficiency programs, benefit all ratepayers, both participants and non-participants alike. Therefore, the IOUs contend that the Commission's existing policy of allowing utilities to recover the costs of utility-sponsored programs from all customers is appropriate. The IOUs also agreed that all their programs save both demand and energy. (TR 143-145, 151, 193, 337, 338; DEF BR 2, 3, 7; FPL BR 15; FPUC BR 1; TECO BR 23) Therefore, according to FPL, separating the ECCR costs for programs that pass the RIM test based on whether the program is characterized as an energy efficiency program or a demand response program "would not provide a meaningful basis for determining costs that opt-out customers would be allowed to avoid." (FPL BR 15)

DEF opposes an opt-out provision and therefore contends that separating costs in the ECCR clause in order to facilitate an opt-out provision is unnecessary. (DEF BR 12) DEF, however, stated that if the Commission desired to implement an opt-out provision, it would not be difficult to separate ECCR costs into those related to energy efficiency programs and those related to demand response programs. (BR 12)

In its brief, OPC noted separating the ECCR into two separate categories may be inconsistent with the fundamental basis of ECCR charges. (BR 3-5) In addition, OPC stated that there may be some merit to FPL witness Koch's testimony that, ". . . because all customers share in the benefits of approved DSM programs, there is no justification for allowing certain customer groups to opt out of paying for those programs." Furthermore, it would seem inconsistent with the Commission's application of FEECA to separate expenditures into two categories so that only certain customers could opt out of the energy efficiency programs while still receiving the benefit of these programs. Finally, OPC contends that the petitioners have not clearly established that their opt-out proposals meet, at a minimum, the Commission's approved RIM cost-effectiveness test. The petitioners do not appear to have fully met their burden of demonstrating that their opt-out proposals safeguard the general body of ratepayers and rate classes against undue rate impacts. (BR 4, TR 143)

In its brief, SACE stated that Wal-Mart's and FIPUG's proposals to opt out of energy efficiency programs are not yet fully developed to warrant Commission approval at this time. Therefore, SACE takes the position that the ECCR costs should not be separated at this time. (BR 1)

Primary Staff Analysis

Staff utilized an exhibit of witness Baker (EXH 3) to demonstrate, for each utility, the proportion of ECCR costs attributed to programs characterized in the exhibit as energy efficiency versus demand response programs. Witness Baker derived EXH 3 from the utilities' 2014 ECCR filings. As shown below in Table 1-1, the percentage of energy efficiency program-related costs relative to total ECCR costs for the four largest IOUs ranges from 25 percent for DEF to 86 percent for Gulf. Under the petitioners' proposals, this range approximates the percentage of ECCR charges from which opt-out customers would be exempted. As shown in the table, over half of ECCR program expenses are related to demand response programs for three of the four largest IOUs. Gulf is the exception, with 14 percent of ECCR expenses related to demand response programs.

Table 1-1
Proportion of ECCR Costs – EE Programs versus Demand Response Programs

Utility	Total ECCR Costs	Energy Efficiency Program Costs		Demand Response Program Costs	
		Amount	% of Total ECCR Costs	Amount	% of Total ECCR Costs
FPL	$196,450,059	$62,626,077	32%	$133,823,982	68%
DEF	$107,340,447	$26,391,913	25%	$80,948,534	75%
TECO	$46,224,522	$16,840,707	36%	$29,383,815	64%
Gulf	$23,592,756	$20,335,079	86%	$3,257,677	14%

Source: EXH 3
[1]Common costs excluded. EXH 3 did not include FPUC.

Wal-Mart witness Chriss contends that separating costs in the ECCR clause is facilitated by the Commission's allocation methodology within the recovery clause. Witness Chriss explains "[e]ach of the four major utilities already separates out their ECCR revenue requirements by energy and demand and specifies the kWh and kW billing determinates for each class, or groups of classes, as applicable, in the exhibits with their ECCR filings." (TR 118; EXH 3) Staff concurs with witness Chriss's interpretation of the Commission's allocation process established by Order No. PSC-93-1845-FOF-EG.[5] In the order, the Commission recognized that there are significant differences among companies that necessitate some deviation from a single methodology. However, as a base line, the Commission adopted the 12 Coincident Peak and 1/13 Average Demand (12 CP and 1/13 AD) allocation methodology for allocating costs associated with dispatchable programs, and it continues to require investor-owned utilities to allocate the costs of all other programs on an energy basis. Under the 12 CP and 1/13 AD method, approximately 92 percent, or 12/13, of the production costs are allocated on a 12 CP basis, and approximately eight percent, or 1/13, are allocated on an average demand, or energy basis.[6] Average demand or energy is simply the relative kWh usage by class. Energy conservation costs continue to be recovered on an energy basis.[7]

The Commission approved 12 CP and 1/13 AD as a uniform methodology for allocating and recovering conservation costs for all investor-owned electric utilities. However, exceptions are allowed when demonstrated to be reasonable, appropriate and necessary.[8]

[5] Order No. PSC-93-1845-FOF-EG, issued December 29, 1993, in Docket No. 930759-EG, In re: Investigation into appropriate method for allocation and recovery of costs associated with conservation programs.
[6] Coincident Peak (CP) is the maximum peak demand of the class which occurs at the time of the system peak. The term "12 CP" refers to the average of each rate class's 12 monthly CP demands in the projected test year.
[7] Order No. PSC-93-1845-FOF-EG
[8] Ibid.

Staff agrees with witness Chriss that because of the Commission's allocation methodology, the four largest IOUs identify costs within their ECCR filings based on demand and energy. (EXH 3) Staff further agrees that this may facilitate the separation of the costs needed to implement the petitioners' opt-out proposals. Staff notes, however, that the Commission's allocation methodology was not designed with the intent of separating ECCR costs for the purpose of implementing an opt-out program. Further, staff notes that the specific costs that are allocated toward demand and energy are not identified in the record for all four of the largest IOUs. For example, whether research and development costs should be allocated between energy efficiency programs and demand response programs was not addressed by any party. Therefore, staff does not believe there is sufficient detail in the record to determine if the specific costs identified under the Commission's current allocation methodology as demand-related versus energy-related are appropriate to be used to implement the proposed opt-out program.

Primary Staff Conclusion

As discussed in Issue 2, staff agrees with the Commission's long-held determination that the costs associated with conservation benefits should be spread to all customers, and sees no compelling evidence in the record that supports a change in this policy. As reiterated by the Commission in its recent DSM goals orders, programs that pass the RIM test benefit all customers, both participants and non-participants alike.[9]

The petitioners have suggested separating the costs in the ECCR clause as a means of implementing the proposed opt-out provision. (TR 118; EXH 3) If the Commission approves staff's recommendation in Issue 2 to deny the petitioners' request for an opt-out provision, this issue is moot, and no changes to current ECCR clause practices are necessary. Therefore, staff recommends that the utilities should not be required to separate their ECCR expenditures into two categories, to facilitate an opt-out provision.

Alternative Staff Analysis and Conclusion

If the Commission approves alternative staff's recommendation in Issue 2, the four largest IOUs will be required to work with parties and staff to develop a limited pilot opt-out program. Implementing a pilot program would require the IOUs to determine the proportion of total ECCR costs that are related to energy efficiency programs paid by each customer that chooses to participate in an opt-out program. Under the Commission's allocation methodology, the four largest IOUs identify costs within their ECCR filings based on demand and energy. (EXH 3) This may facilitate the separation of the costs needed to implement the petitioners' opt-out proposals. However, alternative staff does not believe there is sufficient detail in the record to determine if the specific costs identified under the Commission's current allocation methodology as demand-related versus energy-related are appropriate to be used to implement the proposed opt-out program. Therefore, alternative staff recommends that the appropriate methodology for determining the proportion of total ECCR costs paid by participating customers related to energy efficiency programs be included among the list of topics identified in Issue 3 to be addressed through a workshop.

[9] Order No. PSC-14-0696-FOF-EU, issued December 16, 2014, in Dockets Nos. 130199-EI, 130200-EI, 130201-EI, 130202-EI, 130203-EM, and 130204-EM, In re: Commission review of numeric conservation goals (Florida Power & Light Company, Duke Energy Florida, Inc., Tampa Electric Company, Gulf Power Company; JEA, Orlando Utilities Commission, Florida Public Utilities Company).

A topic of the workshop would be the appropriate methodology to identify and separate energy efficiency ECCR costs for opt-out customers. Additional topics to be discussed in the workshop related to separating the ECCR costs should include: (1) the appropriate allocation of common costs, and (2) the identification and treatment of any administrative costs related to an opt-out provision. The appropriate treatment of these costs within the utilities' ECCR filings was not fully addressed in the petitioners' proposals.

Issue 2: Should the Commission allow pro-active non-residential customers who implement their own energy efficiency programs and meet certain other criteria to opt out of the utility's Energy Efficiency programs and not be required to pay the cost recovery charges for the utility's Energy Efficiency programs approved by the Commission pursuant to Section 366.82, F.S.?

Primary Recommendation: Primary staff recommends that the Commission not pursue an opt-out policy at this time. There is insufficient evidence in the record for the Commission to change its existing policy that all ratepayers benefit from cost-effective DSM programs, therefore all ratepayers should share in the costs. Further, an opt-out policy could result in cost shifting to residential and commercial/industrial customers that are not eligible to opt out under the petitioners' proposals. Additionally, it is probable that an opt-out provision would introduce equity concerns into Florida's DSM programs. Finally, primary staff recommends that the Commission direct the utilities to work with the petitioners to make their existing energy conservation Custom Incentive programs less burdensome and more responsive to customer needs in order to increase customer participation. (Harlow, Lingo, Margolis)

Alternative Recommendation: Alternative staff recommends that the Commission direct staff to conduct a workshop for discussion among the parties and the four largest IOUs on a pilot program that meets the parameters discussed in Issue 3. The Commission should direct the four largest IOUs to develop a pilot opt-out program, and the associated tariffs, within 90 days of the workshop, for Commission review and approval. To the extent possible, the utility proposals shall reflect common program specifics to enable reasonably comparable for evaluation at the conclusion of the pilot. The purpose of the pilot program is to collect data regarding the impact of an opt-out policy on: (1) customer energy and demand savings relative to expected savings under utility-sponsored programs; (2) whether these demand and energy savings are cost-effective under the Commission's approved cost-effectiveness methodology; and (3) whether cost shifting occurs and, if so, at what level. (Shafer)

Positions of the Parties:

<u>FIPUG:</u> Yes. Eligible customers should be allowed to pursue energy efficiency measures at their own expense and not be forced to also pay for utility-specific energy efficiency programs. A properly structured opt-out program is a win-win proposition. The state benefits and its energy efficiency policy is advanced when eligible opt-out customers invest in additional energy efficiency measures with their own resources. The eligible customers benefit by investing in energy efficiency measures best-suited to serve the particular needs of their respective businesses, and not being forced into utility programs that may not fit or be attractive. The utilities benefit when opt-out eligible customers invest in energy efficiency measures that are counted to help meet utility goals, again at no additional costs to the utility or its ratepayers. (The additional energy efficiency resulting from customers opting out should reduce the utilities' programs so that the net effect of the opt-out program is revenue neutral; no costs are shifted to non-participating ratepayers). The ratepayers benefit by additional energy efficiency measures being in place at no costs to them.

Wal-Mart: Yes. Providing this opportunity will enable eligible customers to proactively implement, ***solely at their own expense,*** energy efficiency measures that are best tailored to customers' facilities and operations, thereby maximizing energy efficiency benefits for opt-out customers, for the utilities, for the utilities' other customers, and for Florida as a whole.

PCS: Yes. PCS agrees with FIPUG and Wal-Mart.

FPL: No. All customers benefit from the utility's DSM programs, yet the proposals would shift recovery of prudently incurred costs for approved programs to smaller business and residential customers. The proposals are inconsistent with sound regulatory policy and not aligned with FEECA. Furthermore, the circumstances in other states were proven irrelevant.

DEF: No. Because DEF's goals are set based on programs that are cost-effective under the RIM test, all customers, both participants and non-participants, will benefit from all Energy Efficiency programs. It is therefore not necessary to permit certain customers to opt out of paying for the Energy Efficiency program costs.

TECO: No. All customers benefit from the utilities' DSM programs and the opt-out proponents fail to recognize (or deny) that the impact of such proposals would be to shift the recovery of prudently incurred costs for approved DSM programs from large business customers to smaller business or residential customers.

Gulf: No. Cost-effective demand-side management benefits all customers; therefore all customers should share in the costs of such programs. Allowing select customers to opt out of utility energy efficiency programs is unnecessary and would unfairly shift program administration costs to non-opt-out customers, result in complex and costly new procedures and impact the entire Florida Energy Efficiency Conservation Act process.

FPUC: No, not without the implementation of carefully constructed criteria that will hold all customers and the utility harmless.

SACE: No, not at this time. While SACE believes that Wal-Mart captures more annual energy savings from its stores than the anemic C/I annual energy savings goals set by this Commission, such an "opt-out" policy should be based on best practices in self-directed programs in other states.

OPC: The Proponents do not appear to have fully met their burden of demonstrating that their opt-out proposals adequately safeguard the interests of the general body of ratepayers and various rate classes against undue rate impacts while achieving the intent of FEECA and Section 366.82(2), F. S., utilizing the Commission's approved RIM cost-effectiveness test or other Commission approved tests.

Background and Position of Parties

In 1980, the Florida Legislature enacted the Florida Efficiency and Conservation Act (FEECA), now codified in Sections 366.80–366.85 and 403.519, F.S. For the purpose of implementing FEECA, the Commission adopted Rule 25-17.015, Florida Administrative Code (F.A.C.), which establishes a mechanism whereby unreimbursed costs of conservation programs may be recovered through a "conservation cost recovery clause," also known as the Energy Conservation Cost Recovery (ECCR) clause.[10] When the ECCR clause was established, an important decision was made by the Commission regarding the allocation of conservation costs. The Commission determined that the costs associated with conservation benefits should be spread to all customers, rejecting the notion that only the participants in conservation programs benefit from those programs.[11]

An opt-out provision would allow certain qualifying customers a choice between paying for and participating in utility-funded energy efficiency programs. (TR 506) Although FIPUG and Wal-Mart put forward different proposals (Attachment A), both proposals advocate allowing eligible large customers to opt out of participating in, and paying for, costs associated with utility-sponsored energy efficiency programs. Costs for all types of investor-owned utility-sponsored conservation programs are currently recovered from all ratepayers through the ECCR clause.

FIPUG, Wal-Mart, and PCS Phosphate are seeking relief from paying for energy efficiency program-related ECCR charges, which they believe do not benefit them. The petitioners assert that an opt-out policy is justified because custom incentive programs are unsatisfactory and because the petitioners can implement energy efficiency more effectively on their own. The petitioners further contend that opt-out provisions are offered to large customers in other states. (FIPUG BR 4, Wal-Mart BR 7) Therefore, the petitioners claim that paying the full ECCR costs in Florida places them at a competitive disadvantage and that the Florida economy would become more competitive by allowing an opt-out provision. (Wal-Mart BR 17-18)

Wal-Mart's opt-out proposal is based on its belief that a customer that implements energy efficiency measures on its own benefits other customers. (TR 47) Therefore, Wal-Mart recommends that the Commission should

> redesign the Florida investor-owned utilities' Energy Conservation Cost Recovery ("ECCR") Charges in such a way that the charges for energy efficiency ("EE") are segregated from the demand side management portion of the ECCR charge… allowing customers who meet defined criteria to satisfy their EE responsibilities by implementing their own EE measures. By virtue of their self-implemented measures, such customers would be exempt from paying ECCR charges for the EE portion. (TR 46)

Wal-Mart also states that an opt-out provision will increase cost-effective energy conservation and energy savings. (Wal-Mart BR 6)

[10] Order No. 9974, issued April 24, 1981, in Docket No. 810050-PU, In re: Conservation cost recovery clause.
[11] Ibid.

FIPUG's opt-out proposal is based on its belief that the customer knows its energy efficiency needs better than the utility. (TR 510) FIPUG explains an opt out as giving

> ...certain qualifying customers a choice between paying for and participating in utility-funded energy efficiency measures or self-funding their own cost-effective energy efficiency improvements. A customer that opts out has either implemented (or committed to fund and implement) its own energy efficiency measures or has determined as a result of an energy audit or analysis that there are no cost-effective measures for the customer. (TR 506)

FIPUG argues for an opt-out policy by pointing out that other states have approved an energy efficiency opt-out policy for large customers. (FIPUG BR 2) FIPUG insists that its proposed opt-out provision would not shift costs or harm other customers. (FIPUG BR 3) PCS Phosphate asserts that an opt-out is a good policy that should not be rejected simply because of worries about administrative considerations and costs. (PCS BR 4)

The IOUs argue that all ratepayers benefit from cost-effective demand-side management (DSM) programs. Therefore, the IOUs believe there is no reason for the Commission to change its long standing policy that all ratepayers should share in the costs. The IOUs further state that custom incentive programs allow the petitioners flexibility to design their own energy efficiency projects. (TR 191) Additionally, the IOUs insist that an opt-out policy would shift costs and would unfairly harm non-opt-out customers. (TR 180, 205)

FPL believes that an opt-out provision would harm the general body of ratepayers. (FPL BR 1) FPL also states that an opt-out policy would shift costs to other ratepayers, add administrative costs, and fail to advance the mission of FEECA. (FPL BR 3) DEF states that an opt-out policy is unnecessary because DSM programs that pass the Rate Impact Measure (RIM) test benefit all ratepayers. (DEF BR 2) DEF is also concerned that it will be difficult to hold harmless customers who do not opt out. (DEF BR 1)

TECO insists that "Allowing certain large customers to opt out of paying their fair share of ECCR costs would be contrary to Commission practice and would be inconsistent with the manner in which conservation costs are incurred pursuant to the Commission's implementation of FEECA." (TECO BR 3) Gulf states that an opt-out provision would be "a sharp and unwarranted departure from years of well-reasoned Commission policy and practice." (Gulf BR 1) FPUC states that implementing an opt-out policy would be difficult and that overseeing an opt-out would be outside the Commission's purview, because the Commission does not have authority over the conservation actions of large customers. (FPUC BR 2-3)

SACE states that the opt-out proposals from the petitioners are not sufficiently developed for the Commission to approve. (SACE BR 1)

OPC is concerned that an opt-out policy could harm the general body of ratepayers. (OPC BR 7) OPC states that the petitioners "have not convincingly demonstrated that cost shifting will not occur." (OPC BR 5) OPC also states that petitioners ignore that they benefit from energy efficiency programs that pass RIM even when the petitioners do not participate. (OPC BR 6)

Opt-Out Policies in Other States

Wal-Mart claims that Oklahoma has an opt-out policy, with an eligibility threshold of 15 million kWh of electricity consumption per year aggregated across all customer sites. (TR 54) Wal-Mart witness Baker also asserts that opt-outs exist in South Carolina for Duke Energy, as well as for other utilities in Missouri and West Virginia. (TR 54)

FIPUG details that opt-out states include Texas, Virginia, Arkansas, Indiana, Louisiana, Missouri, North Carolina, Oklahoma, South Carolina, and West Virginia. (TR 512) Self-direct states include several Midwestern states from Ohio to Minnesota, most of the Mountain West and the Northwest United States.[12] (EXH 15) Lastly, FIPUG believes that its petition is similar to processes that other states have already done. (TR 527)

TECO witness Deason opines that just because other states have an opt-out provision does not mean that an opt-out is an ideal path for Florida. (TR 459-460) TECO also comments that if the Commission were to pursue an opt-out policy, the Commission should explore opt-out states' policies, legislative mandates, and cost tests. (TR 496) FPL witness Koch states that special accommodations may exist in other states due to specific legislative and regulatory circumstances. (TR 145) FPL witness Koch declares that the petitioners have not proved that circumstances that led to opt-outs in other states would be germane to Florida. (TR 145)

Like TECO and FPL, DEF witness Duff comments that other states allow opt-outs, but Florida has specific regulatory characteristics such as the FEECA statute. (TR 234) DEF witness Duff also contends "when looking at other states that have opt-out criteria, those criteria are often part of the overall landscape that was created and envisioned for energy efficiency." (TR 269) DEF witness Duff expands on this point by saying "if you've got a piece of legislation around energy efficiency and demand response and an opt-out wasn't contemplated in it, trying to put it in later may not align appropriately." (TR 294-295) DEF also mentions that opt-out energy savings must be verified in Ohio, but not in North Carolina. (TR 274-275)

Staff Analysis:

This issue represents the threshold question of the case. Primary staff's analysis has been separated into four subparts: (1) impact on cost-effective conservation, (2) the potential for cost shifting, (3) equity and fairness concerns, (4) availability of custom incentive programs, and (5) implementation issues. Primary and alternative recommendations appear in each subsection and are summarized at the end of the analysis.

Impact Cost-Effective Conservation

A key question to consider when evaluating an opt-out policy is whether the proposals will result in more cost-effective conservation than when all ratepayers participate in, and pay for, utility-sponsored energy efficiency programs. The Commission currently sets demand-side management (DSM) goals and approves programs based on whether the associated demand and energy savings are cost-effective under the RIM test.

[12] Self-direct programs allow participating customers to direct the dollars they would have otherwise contributed to utility-sponsored programs to their own energy efficiency investments.

The petitioners—FIPUG and Wal-Mart—argue that they know their businesses best. (TR 52; TR 510) PCS Phosphate agrees. FIPUG witness Pollock states "sophisticated energy consumers are better able (than the utility) to invest in cost-effective energy efficiency measures that meet their specific needs." (TR 510) The petitioners also insist that when they invest in energy efficiency on their own, all ratepayers benefit. Wal-Mart witness Baker comments, "[a] customer, whether commercial or industrial, that implements DSM and EE measures on its own yields network benefits for all of the Company's other customers. These network benefits include reduced overall energy cost that result from the reduced load and demand of the customers system." (TR 47)

Witness Baker states that Wal-Mart has made a commitment to improve energy efficiency by decreasing the energy intensity of its buildings by 20 percent by 2020. (TR 49) Wal-Mart uses various energy savings technologies including "daylight harvesting and optimization systems that monitor and adjust lighting intensity," "white membrane roofs…in certain parts of the country in order to lower cooling load," "heat recovery from (Wal-Mart's) refrigeration systems," efficient heating, ventilation, and air conditioning systems, LED lighting, and active dehumidification that decreases electricity consumption. (TR 49-50) FIPUG did not provide specific information on its members' energy efficiency projects, but did state that its members have employees "whose responsibilities include energy efficiency matters." (EXH 19, Bates 6)

The petitioners further argue that paying the ECCR charges takes away from their ability to install cost-effective DSM measures. PCS Phosphate claims "customer charges imposed by the ECCR clause actually deplete the dollars available to those large customers for making the desired energy efficiency improvements." (PCS BR 3)

The utilities counter the petitioners' testimony by stating that because the Commission sets goals and approves programs based on the RIM test, all ratepayers benefit from cost-effective DSM programs. Gulf witness Floyd, adopting the testimony of witness Todd, insists "The Intervenor witnesses correctly recognize the benefits of implementing demand response programs but fail to recognize that cost-effective (i.e. RIM-passing) energy efficiency programs also provide benefits that exceed costs to participating and non-participating customers alike." (TR 338) TECO witness Roche states, "An opt-out provision as proposed by the intervenor witnesses would exempt certain customers from sharing in the cost of investments in energy efficiency which benefit all customers." (TR 389) OPC notes that "witness Chriss acknowledged on cross examination that Walmart's opt-out proposal does not use a RIM test. (TR 128)" (OPC BR 7) OPC argues that, "The lack of application of a RIM test to the proposals tends to demonstrate that the general body of ratepayers will not benefit from these proposals." (OPC BR 7)

The Commission has been presented an opt-out proposal previously when, according to TECO witness Deason, in Docket No. 930759-EG, "Two proposals were considered which would have markedly altered the manner in which costs were allocated and recovered. Both of these proposals contained aspects similar to the proposal of the intervenor witnesses in this proceeding." (TR 444) The Commission's order in Docket No. 930759-EG "found that cost-effective conservation programs benefit all customer classes. Thus, there was no need to give preferential treatment to certain customer classes or even certain customers within those classes." (TR 446-447) Similarly, the "Commission recognized this shared cost/benefit relationship in

Order No. 9974 dated April 24, 1981, wherein the Commission considered a similar opt-out proposal put forth by the Florida Industrial Power Users Group. The Commission rejected the proposal noting as follows: 'Because all customers will enjoy the benefits of such cost avoidance we direct that the authorized costs be recovered from all customers.' " (TR 442)

In addition, it is important that the Commission's goals are based on energy and demand savings from incremental energy efficiency and demand-side management activities. FIPUG's proposal allows eligible customers to opt out without investing in incremental energy efficiency measures. witness Pollock explains that FIPUG's customer eligibility criteria would allow a customer to opt out by providing a letter stating that the customer "has invested or (intends to invest) in energy efficiency <u>or has conducted an energy audit or analysis determining that there are no cost-effective energy efficiency measures</u>." [Emphasis added.] (TR 515)

Potential for Cost Shifting

Wal-Mart presented Exhibits 38 and 39 to support its position that extensive levels of cost shifting are unlikely to occur. However, the utilities believe that an opt-out provision will cause cost shifting to other ratepayers. Gulf witness Floyd says he believes that cost shifting will occur. (TR 368) TECO witness Roche states that an opt-out policy would shift $0.7 to $2.4 million of costs to residential customers. (TR 391) Additionally, FPUC comments that cost shifting would occur. (FPUC BR 4)

The utilities also express concerns that allowing some customers to opt out will result in DSM program costs being spread over fewer ratepayers, while the utilities' Commission-approved goals may be unchanged. DEF notes that if some opt-out customers insisted there were no cost-effective energy efficiency measures, part of DEF's DSM goals would be unchanged. (TR 177) TECO witness Deason states, "[A]llowing certain customers to opt out would result in the total amount of cost-effective conservation costs being spread over fewer customers. This, in turn, would raise rates for those remaining customers and would be inequitable." (TR 447)

As for the change, or lack thereof, in the goals, witness Duff states "it is not clear that he [FIPUG witness Pollock] is proposing that DEF be allowed to count the EE savings from opt-out customers towards its goal...I would note that Mr. Baker [Wal-Mart witness] includes no consideration for adjusting DEF's goals or allowing DEF to count EE savings achieved by opt-out customers." (TR 239) Gulf witness Floyd states, "whether certain customers opt out of those or not doesn't necessarily change the need to have those programs available to other customers." (TR 354) Witness Floyd continues, "We're still obligated to meet the goals and provide programs that will be available to all of our other customers." (TR 354)

Utilities are also concerned about increased administrative costs to implement and maintain an opt-out provision. Witness Deaton states that the opt-out proposal would cause FPL to incur additional administrative costs. (TR 206) DEF witness Duff claims that there will be an administrative cost to verify the eligibility of customers who wish to opt out. (TR 235) Gulf insists "the issue of the administrative cost is obvious." (TR 349)

The IOUs assert that residential customers would experience a negative rate impact from certain large commercial and industrial customers opting out of paying for energy efficiency because of: (1) spreading costs over fewer ratepayers, (2) potentially no or few changes to the DSM goals, and (3) administrative costs from an opt-out provision. FPL estimates an opt-out policy would cause a $1.4 million to $4.6 million rate impact to residential customers, ranging from a two cents to eight cents monthly bill increase. (TR 225) DEF estimates that an opt-out provision would shift $599,000 to $1,979,000 in revenue requirements to residential ratepayers. (EXH 27, Bates 112- 114, 123) TECO estimates that an opt-out provision would increase the residential ECCR charge from 3.6 to 10.9 percent. (TR 391) Gulf estimates that an opt-out provision would increase the residential ECCR charge from 6.8 to 21.2 percent. (EXH 37, Bates 235-236)

In response to a discovery request by OPC, the four largest IOUs estimated the rate impact on a typical residential monthly bill due to an opt-out provision. OPC requested the impact on residential rates under three hypothetical scenarios "whereby the largest (by revenue in each tier) non-residential customers comprising 10%, 20% and 30% of non-residential revenues would be eligible for and take advantage of such an option." (EXHs 11, 27, 34, 37; Bates 123, 210, 235-236) The IOUs' responses to OPC's scenarios are presented in Table 2-1. Staff presents these estimates with the caveat that the full details of an opt-out provision are not yet known.

Table 2-1
Impact on Residential Monthly Bills at Varying Percentages of Non-Residential Customers Opting Out

	Impact on Typical 1,000 kWh Residential Bill		
Utility	**10% opt out**	**20% opt out**	**30% opt out**
DEF	$0.03	$0.06	$0.10
FPL	$0.02	$0.05	$0.08
Gulf	$0.17	$0.34	$0.53
TECO	$0.09	$0.18	$0.27

Sources: EXH 11; EXH 27, Bates 123; EXH 34, Bates 210; EXH 37, Bates 235-236

Wal-Mart argues that opt-out customers would contribute energy savings in excess of the shifted costs. (Wal-Mart BR 14) Wal-Mart also contends that an opt-out "will reduce the utilities' program costs and the utilities' incremental fuel costs, with likely associated reductions in the need for future generation facilities, again without any direct costs being imposed on non-participating customers." (Wal-Mart BR 22)

FIPUG witness Pollock advocates that the Commission "try to develop a program that meets...guidelines so that nobody is harmed." (TR 549) Addressing the cost shifting concern, witness Pollock recommends a pilot program to start slow and see the consequences of implementation of an opt-out program. (TR 550) Lastly, witness Pollock believes a cost shift can be avoided "if done in a prudent and rational way." (TR 545) FIPUG comments that a well-designed opt-out program would avoid cost shifts through "making adjustments to existing energy efficiency programs and counting the energy efficiency measures contributed by opt-out customers." (FIPUG BR 5)

PCS argues that failing to enact an opt-out policy because of a concern over cost shifting would be an "administrative and implementation question" that should not be "sufficient reason for rejecting an otherwise sound policy." (PCS BR 5)

Wal-Mart states that the reduction in ECCR revenues for the four largest Florida IOUs would be a total of $344,040 if Wal-Mart opted out. (EXH 38) Wal-Mart expresses that the impact on the ECCR revenue requirements of the four largest Florida IOUs from Wal-Mart alone opting out would be no more than 0.65 percent. (EXH 38) Nevertheless, this analysis only takes Wal-Mart into account and does not consider the potential for other large commercial or industrial customers, such as FIPUG's members, to opt out. Furthermore, Wal-Mart does not calculate, in Exhibit 38, the cost impact to the utilities from the added administrative expense of an opt-out or the impact on the ability of the utilities to meet the FEECA goals.

Equity Concerns

The petitioners believe there would be no equity issues from an opt-out provision because there would be "no undue burden placed on the utility's remaining customers as a result of the current opt-out proposal." (TR 521) In contrast, the petitioners insist that there is currently an equity concern with paying the full ECCR charges because for the petitioners, electricity is a large operating cost and the markets in which the petitioners operate are competitive. (TR 509-510) Meanwhile, many other states exempt industrial customers from paying for energy efficiency programs. (TR 512) Consequently, the petitioners insist that they are at a competitive disadvantage compared to companies in other states.

In contrast to the petitioners, the utilities insist that an opt-out policy would be unfair to residential customers and other commercial/industrial customers that cannot or do not choose to opt out. FPL witness Deaton states that other customers will have to pay for the costs of an opt-out policy. (TR 223) DEF witness Duff declares that an opt-out provision could require DEF to change its goals. (TR 255) Witness Duff also comments that because in other states, Duke Energy "do[es] not have a separate charge for customers that opt-out, the administrative costs are just lumped in with the overall EE overhead costs." (TR 299)

Additionally, FPL witness Koch notes that large commercial and industrial customers who wish to opt out benefit from load management programs that are paid for by residential customers. (TR 147) Utilities also express that an opt-out policy would be unfair for customers who do not meet the threshold. TECO witness Roche states that an opt-out policy "would be unfair to all customers who do not qualify to opt out or who elect not to do so." (TR 399)

OPC is also concerned that "FIPUG and Wal-Mart's proposals as presented appear to fall short in meeting the Proponents' burden of demonstrating that the proposals would be fair to the general body of ratepayers." (OPC BR 5) OPC believes it is possible that an opt-out provision may shift costs, commenting that the petitioners have neither conclusively shown that utilities' DSM energy efficiency costs will fall or that the petitioners' failure to use a RIM test will leave harmless other customers. (OPC BR 6-7)

In addition to an energy efficiency specific opt-out provision, large commercial and industrial customers would still benefit from load management credits that are paid for by all customers, including residential customers. (TR 214; TR 218) Witness Deaton also expressed that FPL's ECCR credits to large commercial and industrial customers exceed $50 million per year. (TR 219) TECO pays load management customers "incentives to be willing to shed load because their willingness to do so yields benefits to the company and its customers..." (TR 395) TECO witness Roche states that in 2015, TECO has "$47 million budgeted for our ECCR expenditures." (TR 421) Witness Roche continues that FIPUG's interruptible customers in the GSLM-2 and GSLM-3 rates receive $17 million per year in credits while contributing $1.7 million to total ECCR costs. According to witness Roche, "So, they get 35 percent of the money we basically collect to facilitate conservation programs." Witness Roche contends that an opt-out provision would reduce the annual ECCR costs paid for by FIPUG members from $1.7 million to $900,000, resulting in an $800,000 bill reduction for FIPUG's members. (TR 421-422)

Customer Incentive Programs

The four largest Florida IOUs currently offer large commercial and industrial customers custom incentive programs. (TR 191, 362) These programs allow eligible customers to design a custom program which would increase their conservation efforts and allow for rebates within the IOU's programs. The 2014 expenditures by the four largest IOUs are shown in Table 2-2. (EXH 3) All energy efficiency investments approved for a rebate under the custom incentive programs must pass the RIM test. The four largest IOUs stated that customers may suggest projects to be evaluated for a rebate under the custom incentive programs (TR 193-194; EXH 24 Bates 96; EXH 27 Bates 121; EXH 29 Bates 156; EXH 32 Bates 196) Witness Baker states that although he is aware of the custom incentive programs offered by the utilities, to the best of his knowledge, Wal-Mart has not participated. Witness Baker continues, "the process for doing that was so burdened that our energy managers...made a business decision that it wasn't the right thing to do for that particular measure." (TR 74) Witness Baker states that the Florida IOUs' custom incentive programs are burdensome because "there's many forms you have to fill out" and the programs have "a number of different types of audit activity you have to do." (TR 82) Staff notes, however, that implementing the opt-out proposals could also result in audits and other requirements for the opt-out customers, especially if energy efficiency savings from these customers are counted towards utility goals. Witness Baker did not offer suggestions to make the utilities' custom incentive programs less burdensome. (TR 81-84) Primary staff believes that rather than implementing a complex and potentially costly opt-out policy, the Commission should direct the utilities to work with the petitioners to make the custom incentive programs less burdensome and more responsive to customer needs in order to increase customer participation.

Table 2-2
Custom Incentive Programs – 2014 IOU Expenditures

Utility	Total Expenditures	Incentives
DEF	$46,117	$20,944
FPL	$289,113	$245,132
Gulf	$1,665	$1,000
TECO	$129,582	$101,415

Source: EXH 3

Implementation Issues

An opt-out policy would lead to numerous implementation issues that could add complexities to Commission processes and increase administrative costs. The petitioners argue that an opt-out can be implemented in such a way as to prevent cost shifting because an opt-out provision would reduce expected program costs. (TR 122, 511) Issue 3 addresses implementation issues in greater detail.

Having stated that an opt-out provision will not shift costs, Wal-Mart then recommends that the Commission allow utilities to count estimated or reported energy efficiency from opt-out customers towards DSM goals. (TR 59) Wal-Mart also suggests that the IOUs split the ECCR charge into an energy efficiency portion and a DSM portion. (TR 70) Separating costs in the ECCR clause is discussed in Issue 1.

While the petitioners advocate splitting the ECCR charge and counting opt-out energy efficiency investments toward goals, the utilities note that both Commission and utility internal processes would have to change and that such a change would add costs. FPL witness Deaton identifies "numerous process and system modifications that would be required in order to ensure proper tracking and handling of many of the accounts." Witness Deaton go on to say that, "Billing system changes include identification of the ECCR opt-out customers and creation of the additional charges in the rates and billing tables. New charges have to be added to...data warehouse, rate reports and other financial reports." (TR 221-222) TECO asserts that an opt-out policy would cause the company to make programming changes to the customer information and billing system, changes to forecasting processes, and additional work for the customer service department. (EXH 29, Bates 138-139)

Gulf states that not only would an opt-out policy "create additional costs and complexities" but also "will impact Gulf's ability to achieve DSM goals established by this Commission." (TR 338) DEF comments that it would need to adjust the Commission's annual DSM goals. (EXH 27, Bates 112-113)

Primary Staff Analysis

Impact Cost-Effective Conservation

The record is inconclusive over whether the ability to opt out of paying the ECCR charge will spur greater cost-effective conservation by large customers. Reducing ECCR charges for these large customers will reduce their bills. While these customers may increase their spending due to lower bills, there is no guarantee that these dollars will be invested in energy efficiency measures. Wal-Mart witness Baker states "the customer implementing the EE measure has every incentive to ensure that the implemented measures are cost effective." (TR 47) However, witness Baker stated that Wal-Mart does not use the Commission-approved cost-effectiveness tests such as the RIM test, the Participants' test, or the Total Resource Cost test. (TR 80) Because of this answer and a lack of further specifics on how the company and others would evaluate an energy efficiency investment, staff cannot definitely agree with Wal-Mart that an opt-out provision would lead to more cost-effective energy efficiency.

Potential for Cost Shifting

Primary staff believes that it will be difficult to design an opt-out policy in such a way as to prevent cost shifting to other ratepayers. At a minimum, preventing cost shifting would require that all additional administrative costs be paid by opt-out customers. Additionally, staff notes that preventing cost shifting would also require the Commission to either: (1) revisit the IOUs' DSM goals or (2) count cost-effective verified opt-out savings towards the IOUs' DSM goals. However, the record is inconclusive regarding whether revisiting the IOUs' DSM goals or counting verified opt-out customer savings towards the IOUs' DSM goals would prevent cost shifting.

Equity Concerns

Primary staff notes that a key contention of the petitioners is that they know their businesses best and are already making energy efficiency investments; therefore they should be able to opt out of paying for utility-sponsored energy efficiency programs. (TR 46; TR 118; TR 510) Primary staff counters that residential and small commercial/industrial customers also invest in energy efficiency. Under the petitioners' proposal, however, these customers would continue to pay the full ECCR charge. In addition, primary staff agrees with DEF witness Duff's statement that the administrative costs of an opt-out provision could be combined with overall energy efficiency overhead costs. This practice would mean that ratepayers who do not opt out are unfairly burdened with the administrative costs of accounting for opt-out customers. On the other hand, forecasting and separating the administrative costs of an opt-out provision may also be burdensome and costly for the utility and its ratepayers.

Primary staff does not find sufficient evidence in the record to guarantee that opt-out customers would pay for all increased administrative costs, including the costs of internal changes such as billing system changes and Commission-specific changes such as changes to annual reporting and DSM goals. The petitioners have also not provided convincing evidence that other customers will not be harmed due to the interaction of an opt-out provision with the Commission's obligation to set goals under FEECA. Moreover, staff notes that aggregation of accounts (as proposed by Wal-Mart and FIPUG) may cause equity issues for single stores or smaller chains. If large chains such as Wal-Mart can aggregate stores to decrease their ECCR charges and smaller stores cannot meet the threshold, then the operating cost of Wal-Mart stores will have unfairly decreased relative to the operating cost of Wal-Mart's competitors. (TR 202)

Customer Incentive Programs

The Commission's most recent DSM goals order requires that approved energy efficiency savings pass the RIM test and have a payback period greater than two years to minimize the number of free riders. Primary staff is concerned that Wal-Mart, FIPUG, and others would be able to opt out of paying for energy efficiency programs without guarantees that opt-out customers would achieve energy efficiency savings that would pass the RIM test and would have a payback period greater than two years.[13] In response to questioning by OPC, witness Baker acknowledged that Wal-Mart's proposal does not rely on a RIM test. (TR 80) Witness Chriss, however, states that if the Commission wants to run a RIM test on an opt-out customer's programs, "I don't think we'd necessarily be opposed to that." (TR 128) FIPUG was silent on using the RIM test on opt-out customers' energy efficiency investments.

Utility-sponsored programs that pass the RIM test put downward pressure on rates and are therefore beneficial to the general body of ratepayers. The utilities' Commission-approved goals are based on the RIM cost-effectiveness test. (TR 339) Opt-out customers have proposed avoiding ECCR payments by making (or promising to make) energy efficiency decisions that are beneficial to these customers. It is reasonable to expect that some of these investment decisions will not pass the RIM test. Historically, the Commission has encouraged customers to use energy efficiently. Any customer has an incentive to make energy efficiency decisions that are in his or her own best economic interests. However, it is the role of the Commission to ensure that utility-sponsored programs and related policies are in the best interest of the general body of ratepayers. Primary staff does not believe Wal-Mart and FIPUG have provided sufficient evidence that their

Implementation Issues

Primary staff believes that an opt-out provision would be complex to implement in an appropriate manner that protects ratepayers who do not opt out. Counting savings from opt-out customers toward utility goals would entail additional utility actions and administrative costs, such as verification of opt-out customer savings and more complex annual FEECA reports. Additionally, staff observes that the record is incomplete on the full implementation details of an opt-out policy. An opt-out policy would require changes to the annual ECCR filings, DSM reporting, and the Commission's DSM goals. Such required changes are discussed in greater detail in Issue 3. As discussed above, it is reasonable to expect that at a minimum, an opt-out provision would require: (1) changes in billing, (2) more complex ECCR filings, and (3) verification that opt-out customers meet required thresholds. It is reasonable to expect that these efforts would have corresponding administrative costs.

Conclusion

Primary staff recommends that the Commission deny the petitioners' request for an opt-out provision for eligible large commercial and industrial customers. The Commission sets goals based on the RIM test. Cost-effective energy efficiency programs that pass the RIM test benefit

[13] Order No. PSC-14-0696-FOF-EU, issued December 16, 2014, Dockets Nos. 130199-EI, 130200-EI, 130201-EI, 130202-EI, 130203-EM, and 130204-EM, In re: Commission review of numeric conservation goals of FPL, DEF, TECO, Gulf, FPUC, JEA, and OUC, pg. 43.

all ratepayers due to downward pressure on rates. The petitioners have not provided convincing evidence for the Commission to alter its long-held policy that since all ratepayers benefit from cost-effective DSM measures, all ratepayers should share in the costs. Additionally, staff observes that an opt-out policy will be difficult to implement without some degree of cost shifting to other ratepayers. As a result, equity concerns, whether from residential customers or from smaller commercial and industrial customers who cannot meet the opt-out criteria, seem likely to arise from an opt-out policy.

The four largest IOUs currently offer custom incentive programs. (TR 191, 362) Primary staff believes that these programs are a viable alternative to an opt-out program. Under the custom incentive programs, large customers can suggest energy efficiency investments and receive a rebate if the projects pass the RIM test. (TR 193-194) During the hearing, however, Wal-Mart witness Baker noted that Wal-Mart does not take advantage of these custom incentive programs because "the process was so burdened." (TR 74) FIPUG witness Pollack asserts that participation in these custom incentive programs is relatively small. (TR 537) Primary staff recommends that the Commission direct the utilities to work with the petitioners to make the custom incentive programs less burdensome and more responsive to customer needs in order to increase customer participation.

Alternative Staff Analysis

The petitioners have stated that businesses are in the best position to know their own opportunities for energy conservation. (TR 27, 510) Therefore, the petitioners contend that they can increase energy savings relative to utility-sponsored programs, if they are exempt from paying the energy efficiency (EE) program-related costs through the Energy Conservation Cost Recovery (ECCR) clause. (TR 516) While the petitioners have not provided persuasive evidence that demand and energy savings will increase if the Commission offers an opt-out program, staff notes that no parties have provided contrary evidence.

Alternative staff believes that an opt-out provision would be consistent with the intent of FEECA if indeed these large business customers could produce demand and energy savings, independent of utility programs, that were determined to be cost effective under the current Commission approved standard, the RIM test. The Legislature's intent of FEECA is addressed in Section 366.81, F.S., which states:

> The Legislature finds and declares that *it is critical to utilize the most efficient and cost-effective* demand-side renewable energy systems and *conservation systems* in order to protect the health, prosperity, and general welfare of the state and its citizens...The Legislature further finds and declares that ss. 366.80-366.83 and 403.519 *are to be liberally construed* in order to meet the complex problems of reducing and controlling the growth rates of electric consumption and reducing the growth rates of weather-sensitive peak demand; increasing the overall efficiency and cost-effectiveness of electricity and natural gas production and use; encouraging further development of demand-side renewable energy systems; and conserving expensive resources, particularly petroleum fuels. [Emphasis added.]

Alternative staff notes that if the savings from these customers' efforts are cost-effective under the Commission's cost-effectiveness methodology, an opt-out provision could also be beneficial to the general body of ratepayers. That is, if the energy efficiency investments made by the petitioners as the result of an opt-out program pass the RIM test, these investments will tend to put downward pressure on rates. (TR 339) Staff notes that Wal-Mart witness Baker acknowledged that Wal-Mart does not use the RIM test in reviewing potential energy efficiency investments. (TR 80) Witness Chriss, however, stated that if the Commission wishes to run a RIM test on an opt-out customer's programs, "I don't think we'd necessarily be opposed to that." (TR 128)

As discussed previously, the petitioners have not provided compelling evidence that demand and energy savings will increase if the Commission offers an opt-out program. In addition, the petitioners have not provided evidence that any demand and energy savings that do occur would meet the Commission's current approved cost-effectiveness methodology, i.e., pass the RIM test and have a payback greater than two years. Alternative staff believes, however, that the only way to fully vet this supposition is through a limited scope pilot program to collect the necessary data on the impact of an opt-out policy on: (1) customer energy and demand savings relative to expected savings under utility-sponsored programs; (2) whether these demand and energy savings are cost-effective under the Commission's approved cost-effectiveness methodology; and (3) whether cost shifting occurs and, if so, by how much.

Alternative staff believes that an opt-out policy could result in cost shifting to customers ineligible to opt out as well as eligible customers electing not to opt out. The IOUs and OPC expressed concern that an opt-out provision will result in cost shifting to customers that are either ineligible to opt out or choose not to. (TR 368, 391, 447; FPUC BR 4) Wal-Mart presented Exhibits 38 and 39 to support its position that extensive levels of cost shifting are unlikely to occur. Addressing the cost shifting concern, FIPUG witness Pollack advocates a pilot program to start slow and see the consequences of an opt-out provision. (TR 550) Alternative staff agrees that a limited scope pilot program can be used to determine the level, if any, of cost shifting or cost savings, for the general body of ratepayers.

There is conflicting evidence in the record regarding whether the petitioners desire an opt-out provision which includes FPUC. Through testimony by witness Baker, Wal-Mart stated that these recommendations would apply to the four largest investor-owned utilities, Florida Power & Light, Duke Energy Florida, Tampa Electric Company, and Gulf Power Company. (TR 46) In response to staff interrogatories, however, Wal-Mart indicated that the proposal could apply to Florida Public Utilities as well. (EXH 22, Bates 35) FIPUG states that to the extent Florida Public Utilities has customers who would be eligible, they should be able to participate. (EXH 20, Bates 19) Given the relatively small customer base of FPUC, alternative staff is concerned that a pilot program may unnecessarily burden FPUC's ratepayers. Therefore, alternative staff believes it is appropriate to limit the pilot program to the four largest IOUs: DEF, FPL, Gulf, and TECO. These four IOUs should be sufficient to collect the needed data to evaluate an opt-out policy.

Alternative staff believes there is a potential that allowing large customers to opt out of a portion of ECCR charges and self direct these dollars toward conservation efforts could result in higher demand and energy savings. If these customers can achieve higher cost-effective savings, this could forward the goals of FEECA and reduce costs for the general body of ratepayers, assuming these costs and savings are documented. Although the petitioners did not provide fully detailed opt-out proposals, alternative staff believes additional details can be discussed at a staff workshop. FIPUG witness Pollack did suggest to "start slow, but get it started and get the discussion on the table about what it would take to make this work and take it from there and put all the right minds in the right room and we'll come up with a solution." (TR 550) Therefore, staff recommends that the Commission direct the IOUs to work with the petitioners to develop a draft limited scope pilot opt-out program for Commission review, with a desire that the utilities work together to develop commonality in program specifics. In order to reduce the potential risk of cost shifting to other ratepayers, the draft pilot program must meet the parameters discussed in alternative staff's analysis in Issue 3. The purpose of the pilot program is to collect data regarding the impact of an opt-out policy on: (1) customer energy and demand savings relative to expected savings under utility-sponsored programs; (2) whether these demand and energy savings can be achieved under the Commission's approved cost-effectiveness methodology; and (3) evaluate whether cost shifting occurs and, if so, by how much.

Conclusion

Alternative staff recommends that the Commission should direct staff to conduct a workshop or workshops for discussion among the parties to develop program standards for a limited scope pilot program that meets the parameters discussed in alternative staff's analysis in Issue 3. The Commission should direct that within 90 days of the workshop, the four largest IOUs should submit pilot opt-out program standards for Commission review and approval for implementation January 1, 2017, consistent with the parameters established in the alternative staff recommendation for Issue 3. The program standards shall also reflect any additional implementation details that are developed at the workshop. Alternative staff also recommends that to the extent possible, the four largest IOUs work together to develop commonality in program specifics.

The IOUs should keep staff and the petitioners engaged in fulfilling the Commission's intent as questions arise. The purpose of the pilot program is to evaluate customer demand and energy savings, whether these savings are cost-effective, and the net impact on costs recovered from other ratepayers through the ECCR.

Alternative staff recommends that the parties discuss at workshop an opt-out pilot program design in which customers participating in the pilot program will continue to pay the entire ECCR charge throughout the pilot program. At the end of each year, opt-out customers could receive a refund/credit for a portion of ECCR charges, capped at the energy efficiency program-related ECCR costs minus any administrative costs. To receive a refund/credit, each participating customer would be required to provide documentation to its IOU of the qualified energy efficiency investments made during the year.

Issue 3: If the Commission allows proactive customers to opt out of participating in, and paying for, a utility's Energy Efficiency programs, what criteria should the Commission apply in determining whether customers who wish to opt out are eligible to do so?

Primary Recommendation: If the Commission approves the primary recommendation in Issue 2, then Issue 3 is moot. (Harlow, Lingo, Margolis)

Alternative Recommendation: If the Commission approves the alternative staff recommendation in Issue 2, the Commission should direct staff to conduct a workshop with the parties to develop implementation of an opt-out pilot program for the four largest IOUs. Following the workshop, these four IOUs should be required to file an opt-out pilot proposal, and the associated tariffs, within 90 days based on the framework provided in alternative staff's discussion of this issue, including: (1) eligible customers should be determined based on an annual energy usage threshold of 15 million kWh, with no account aggregation allowed; (2) any administrative costs associated with an opt-out policy must be paid by the customers that elect to opt out and (3) any energy efficiency savings from an opt-out customer counted toward utility DSM goals must be incremental savings that meet the same cost-effectiveness criteria that utility-sponsored energy efficiency savings already must meet, and must be measureable and verified. The resulting proposed opt-out program standards and other necessary implementation details would be subject to Commission approval through the PAA process. Alternative staff also recommends that, to the extent possible, the four largest IOUs strive for commonality in their opt-out programs. The Commission should also direct the IOUs to engage with staff and the parties in fulfilling the intent of these guidelines as questions arise. (Shafer)

Position of the Parties:

FIPUG: The eligibility criteria should be as set forth by FIPUG expert witness Jeff Pollock in his pre-filed testimony.

Wal-Mart: The eligibility criteria should be as set forth in the surrebuttal testimony of Mr. Kenneth E. Baker, filed in this docket on May 20, 2015.

PCS: PCS agrees with the eligibility criteria described by FIPUG.

FPL: There is insufficient evidence in the record to identify any appropriate criteria which the Commission could apply to determine whether customers would be eligible to opt out of certain ECCR charges. Only arbitrary, self-serving criteria have been proposed, exacerbating the potential for future customer claims of unfair treatment.

DEF: Any opt-out policy should be designed to not result in any cost-shifting to customers who do not or cannot opt out. There is insufficient evidence in this record for the Commission to meet this objective and specifically determine the criteria for determining eligibility for opt-out customers.

TECO: The Commission should reject the very generally described opt-out proposals of FIPUG and Wal-Mart and thereby render this issue moot. If the Commission did have to decide this issue, it is clear that the criteria would be difficult and costly to devise and administer.

Gulf: The Commission should apply criteria to ensure that the utility and the non-opt-out customers are not harmed by the customers that elect to opt out. Considerations could include allowing utilities to adjust their DSM goals based on lost energy savings or allowing utilities to count reported savings toward their existing goals, requiring that incremental administrative costs associated with the opt-out program to be borne by the cost-causers and ensuring that non-opt-out customers are not required to bear additional expense.

FPUC: Criteria should be established that hold all customers, as well as the utility, harmless. The record does not, however, provide support for the establishment of such criteria; thus, a subsequent proceeding would be necessary to better define such criteria, appropriate allocation of costs, and impact on utility conservation goals.

SACE: SACE reiterates that criteria should be based on best practices from self-direct programs in other states. The criteria proposed by Wal-Mart do not rise to the level of best practices. It is not clear that the Commission can establish generally applicable criteria through the commission order.

OPC: While OPC has reservations about whether the opt-out programs as presented should be approved, at a minimum, the interests of the general body of ratepayers and various rate classes should be adequately safeguarded against undue rate impacts while achieving the intent of FEECA and Section 366.82(2), Florida Statutes, and the Commission should require that any qualifying proposals meet its approved cost-effectiveness test (RIM), or other Commission approved tests.

Staff Analysis:

Positions of the Parties

The petitioners, Wal-Mart and FIPUG, propose criteria to determine whether customers will be allowed to opt out of utility-sponsored energy efficiency programs. Florida's investor-owned utilities argue that there is insufficient evidence in the record to support the intervenors' opt-out criteria. The IOUs also claim that the evidence in the record is too general to implement an opt-out policy and that Wal-Mart and FIPUG have conflicting recommended criteria. Wal-Mart argues that to be allowed to opt out, customers should "implement their own energy efficiency programs and meet certain other criteria." (TR 50) The criteria that Wal-Mart recommends for customers to opt out include:

- "Aggregated consumption by a single customer of more than 15 million kWh of electricity per year across all eligible accounts, meters, or service locations within each Company's service area." (TR 53)

- "To be designated an eligible account that account may not have taken benefits under designated EE programs within 2 years before the period for which the customer is opting out." (TR 53)

- "An eligible account may not opt in to participate in the designated EE programs for 2 years after the first day of the year of the period in which the customer first opts out." (TR 53)

- "The customer must certify to the Company that the customer either (a) has implemented, within the prior 5 years, EE measures that have reduced the customer's usage, measured in kWh per square foot of space, or other similar measure as applicable, by a percentage at least as great as the Company's energy efficiency reductions through its approved EE programs...or (b) has performed an energy audit or energy use analysis...and confirms to the utility, that the customer has either implemented the recommended measures or that the customer has a definite plan to implement qualifying EE programs." (TR 53-54)

FIPUG suggests that "eligibility be limited to loads of at least 1 megawatt (MW) either at a single delivery point or through aggregation, provided that each of the aggregated facilities are located in the utility's service area and are under common ownership and operation." (TR 514) FIPUG also recommends that customers that opt out of the ECCR charge provide a signed letter to the utility declaring that the customer "has invested (or intends to invest) in energy efficiency or has conducted an energy audit or analysis determining that there are no cost-effective energy efficiency measures." (TR 515) Moreover, FIPUG proposes that the letter of attestation contain the monitorable energy savings and be signed by a certified energy manager or licensed professional engineer. (TR 516)

PCS supports the 1 MW eligibility criterion described by FIPUG witness Pollock. (PCS BR 6) However, Wal-Mart's and FIPUG's criteria also share commonalities, specifically aggregation across multiple delivery points and certifications from the customer to the utility. (TR 53, 514)

FPL states that the proposed eligibility criteria between Wal-Mart and FIPUG conflicts. (FPL BR 1) FPL also argues "Rule 25-6.102, Florida Administrative Code, prohibits billing practices which seek to combine, for billing purposes, the separate consumption and registered demands of two or more points of delivery. Both of the opt-out proposals would do exactly that." (FPL BR 17) Although DEF opposes an opt-out provision, DEF states that Wal-Mart's suggestion to opt-out of energy efficiency charges based on kilowatt-hours of consumption rather than megawatts of demand would be more appropriate. (DEF BR 9) Like FPL, DEF opposes customer aggregation of separate locations. (DEF BR 9)

TECO expressed concern that the opt-out criteria are too general, insufficient, and would lead to ongoing controversy. (TECO BR 24) Gulf states that Wal-Mart's and FIPUG's proposed criteria do not ensure that the utility and the remaining customers are not harmed. (Gulf BR 11) FPUC comments that creating any opt-out criteria that are consistent with FEECA and contribute to meeting a utility's conservation goals would be difficult. (FPUC BR 3, 4)

OPC requests that eligibility criteria "safeguard the interests of the remaining general body of ratepayers and various rate classes against undue rate impacts." (OPC BR 2) OPC also states that FEECA should guide opt-out eligibility criteria, which should include the costs and benefits to customers and the general body of ratepayers. (OPC BR 8)

SACE states opt-out criteria should be based on the evaluation, measurement, and verification (EM&V) methodologies from other states' self-directed programs. (SACE BR 1) SACE believes Wal-Mart and FIPUG's proposals are "not yet fully developed to warrant approval." (SACE BR 1)

A significant difference in eligible participants results from the differences in the eligibility criteria proposed by Wal-Mart versus the FIPUG proposal. Those differences are addressed in the following subsections.

Energy versus Demand Threshold

Wal-Mart witness Baker suggested customers must meet a 15 million kWh annual aggregated sales threshold to opt out. (TR 53) For 2014, Wal-Mart stated it had 131 stores in FPL's, 66 in DEF's, 36 in TECO's, and 25 in Gulf's respective service territories. (EXH 21, Bates 31) Wal-Mart's proposal would allow for aggregation of accounts for the stores in each IOU's territory in order to meet the sales threshold. In contrast, FIPUG witness Pollock proposed a 1 MW demand threshold criterion.

The four largest IOUs provided data on the number of accounts that could meet Wal-Mart's and FIPUG's threshold eligibility criteria, assuming no accounts are aggregated. The data are presented in Table 3-1 below.

Table 3-1
Number of Eligible Accounts under Proposed Thresholds

Utility	Customer Accounts that Meet Wal-Mart's 15 million kWh Threshold (Unaggregated)	Customer Accounts that Meet FIPUG's 1 MW Threshold (Unaggregated)
FPL	131	945
DEF	79	521
TECO	47	212
Gulf	30	88
Total	287	1,766

Sources: EXH 24, Bates 92-93; EXH 27, Bates 116-117; EXH 29, Bates 143-144; EXH 32, Bates 194-195

As Table 3-1 shows, the four largest IOUs estimate that the annual sales criterion proposed by Wal-Mart would result in up to 287 potential opt-out customers. In comparison, the demand criterion advanced by FIPUG would result in up to 1,766 potential opt-out customers. In contrast, FIPUG witness Pollock stated that if you adjust Wal-Mart's 15 million kWh annual sales criterion to demand, the criterion would correspond to approximately 3.0 to 3.5 MW of demand. (TR 534)

Wal-Mart indicated a willingness to change the specific number of annual kWh sales necessary to qualify for an opt-out policy and further refine its proposed criterion. (TR 22-23) Wal-Mart also stated that it would be open to using FIPUG's 1 MW of demand criterion provided it has a contiguous type of property. (TR 67)

Table 3-2 indicates the number of accounts that could meet Wal-Mart's and FIPUG's differing aggregated criteria. DEF and Gulf did not provide data as part of the record.

Table 3-2
Impact of Account Aggregation on Eligible Accounts

Utility	Customer Accounts that meet Wal-Mart's 15 million kWh Threshold (Aggregated)	Customer Accounts that meet FIPUG's 1 MW Threshold (Aggregated)
FPL	71,000	84,000
DEF	Not Specified	Not Specified
TECO	9,957	Not Specified
Gulf	Not Specified	Not Specified

Sources: EXHs 24, 27, 29, 32; Bates 92, 93, 116, 117, 143, 144, 194, 195

Table 3-2 shows that aggregation of accounts significantly increases the number of customers that could potentially opt out under the proposed thresholds. For example, FPL estimates that FIPUG's unaggregated criterion could result in 945 eligible accounts. (Table 3-1) In comparison, FPL estimates that FIPUG's aggregated criterion could result in 84,000 eligible accounts. (Table 3-2) TECO estimates that Wal-Mart's unaggregated criterion could result in 47 eligible accounts (Table 3-1). In comparison, TECO estimates that Wal-Mart's aggregated criterion could result in 9,957 eligible accounts. (Table 3-2)

Account Aggregation

The parties disagreed about whether the aggregation of customer accounts should be allowed in meeting the suggested thresholds. FIPUG's witness argues for account aggregation. (TR 514) Wal-Mart similarly advocates that in order to meet the proposed opt-out thresholds, customers should be allowed to aggregate all customer accounts within a utility's service territory. (TR 51) For example, with aggregation, all Wal-Mart accounts within a utility's service territory could count toward Wal-Mart's suggested 15 million kWh sales threshold.

FPL witness Deaton testifies that aggregation would be discriminatory and contrary to Section 366.03, F.S. (TR 202) According to witness Deaton, "Individually-owned retail stores would be at a competitive disadvantage if a chain store such as Wal-Mart were allowed to opt out of certain electric charges based on the aggregate load over multiple customer accounts, while customers with similar loads could not because they do not happen to be part of a chain." (TR 202) DEF witness Duff states that aggregation would be costly, hard to verify, and illogical. (TR 238) TECO witness Deason expresses some skepticism, saying "there are questions about whether it should or should not be aggregated." (TR 471)

Potential Changes to Commission Proceedings and Rules

Current Commission and utility processes would require change in order to implement an opt-out provision. FPL states that it "would need to create a separate set of ECCR clause factors for opt-out customers. This will basically require duplicating the current ECCR processes including projection and true-up filings and the resulting FPSC audit." (EXH 24, Bates 89) DEF remarks that it would need to modify the Commission's annual goals. (EXH 27, Bates 113)

TECO states that its forecasting practices would need to be modified. (EXH 29, Bates 138) Gulf comments that it would have to identify opt-out customers in its DSM annual reports and the whole FEECA process could be affected. (EXH 32, Bates 191) Gulf declares "Removing large sets of customers from the potential list of participants upsets the design of both the (FEECA) goals and the plan and impacts utilities' ability to meet the established goals." (EXH 32, Bates 191)

Staff notes that in order to implement an opt-out policy, the following Commission activities would be affected and potentially require change: (1) DSM goals, (2) the annual ECCR filings and proceedings, and (3) each utility's annual DSM report. All of these processes are governed by Commission rules. Staff observes that changing these processes in order to implement an opt-out provision would potentially require rulemaking.

The first rule that may require modification is Rule 25-17.0021, F.A.C., Goals for Electric Utilities. This rule states that the Commission must set conservation goals for each utility every five years and that the utility must propose goals for ten years. Additionally, Rule 25-17.0021(4)(d), F.A.C., requires that the utility submit for approval a DSM plan with "the total number of customers or appropriate unit of measure in each class of customer (i.e. residential, commercial, industrial, etc.) for each year in the planning horizon." Therefore, Rule 25-17.0021, F.A.C., may need to be modified to account for opt-out customers in the goals proceeding. Third, Rule 25-17.0021, F.A.C., also contains the requirements for each utility's annual FEECA reports. These reports are required to be filed with the Commission each year by March 1 to provide information on each utility's efforts to meet its DSM goals. In order to implement an opt-out provision, the reporting requirements specified in the rule may have to change if savings from opt-out customers are counted toward the utilities' goals.

Another rule that would likely be impacted is Rule 25-17.015, F.A.C., Energy Conservation Cost Recovery. This rule states that each utility shall file an annual final true-up filing showing ECCR costs and revenues for the most recent twelve month historical period, an annual estimated/actual true-up showing eight months actual and four months projected ECCR costs and revenues, an annual projection showing twelve months projected costs, and ECCR factors for the twelve month period beginning January 1 following the hearing. As discussed in Issue 1, staff believes a permanent opt-out provision, as proposed by the petitioners, may require rulemaking to modify Rule 25-17.015, F.A.C., because utilities will have to create a different set of ECCR factors for opt-out customers.

Potential for Cost Shifting

The parties disagree about whether an opt-out provision can be designed that avoids cost-shifting to customers, such as residential customers or smaller commercial and industrial customers, who do not meet the opt-out thresholds or elect not to participate in an opt-out program.

Wal-Mart argues that opt-out customers' energy savings would exceed the cost shift. (Wal-Mart BR 13). Wal-Mart argues that a single large commercial or industrial customer that opted out would shift only 0.03 percent of ECCR costs for FPL, 0.04 percent for DEF, 0.17 percent for TECO, and 0.65 percent for Gulf while contributing energy savings in excess of the cost shift. (EXH 38) Counting the benefits from energy savings as exceeding the lost revenues from opt-out customers, Wal-Mart witness Chriss does not expect an opt-out to cause any cost shifting. (TR 122)

FIPUG believes an opt-out customer will not create a cost shift because energy efficiency investment by an opt-out customer "is no different in concept from the utility directing its own cost-effective EE program for the benefit of its customers." (TR 520) FIPUG witness Pollock states "if the power and energy savings of an opt-out customer can also be counted by the utility toward meeting its conservation goals, the utility can reduce its expenditures. In other words, appropriately, there would be no costs to shift." (TR 511) Finally, FIPUG states that the only circumstance in which non-opt-out customers could be impacted is if the utility ignores the documented savings from the opt-out customers while still incurring the same level of energy efficiency program costs. (TR 521)

FPL, however, believes that an opt-out would result in cost shifting. (FPL BR 3) FPL witness Koch testifies that the result of the petitioners' proposals is the same, "to shift prudently incurred energy conservation costs from "large" business customers, such as the companies they represent, to residential and small business customers." (TR 142-143)

DEF comments that it is presently unclear whether cost shifting would occur; DEF believes implementation and opt-out customer behavior will determine whether cost shifting occurs. (TR 258) DEF asserts "any opt-out policy must be designed so that no one, including the utility and/or any customer who does not or cannot opt out, is harmed by any customer opting out of paying for their share of particular charges." (TR 230)

TECO asserts that an opt-out program would result in shift costs. (TECO BR 24) Witness Deason states, "if you take a segment of the customers which are currently being allocated costs, and they are taken out of that allocation, and the amount of cost stays the same, well, then it's going to increase costs for the remaining customers. That's just a mathematical certainty." (TR 474) TECO witness Roche states that the value of energy savings from opt-out customers as well as the equity impacts to customers who do not opt out would be difficult to determine. (TR 419)

Gulf insists that the opt-out "proposals would result in shifting of DSM-related costs to residential and small commercial customers who do not qualify to opt-out." (Gulf BR 2) Gulf disputes Wal-Mart's and FIPUG's claim that program costs would fall enough to equal the decrease in program revenues. (Gulf BR 2) Gulf comments that commercial and industrial programs would continue to operate, and although variable program costs for commercial and industrial customers may decline, "Gulf would continue to incur fixed program costs in the form of labor, overhead, vendor contracts, etc. and variable costs in the form of incentive payments to non-opt-out customers." (Gulf BR 3)

FPUC believes "the record further reflects that, due to program fixed costs, there will likely be little or no savings produced through the implementation of an "opt out" program; thus, cost shifting to the remaining body of ratepayers would occur, contrary to the Petitioners' assertions." (FPUC BR 4)

OPC is concerned about cost shifting, stating "the information provided by the utilities in response to OPC discovery tends to indicate that cost shifting may well take place...Further, Hearing Exhibit 38 introduced by Walmart during redirect appears to indicate that cost shifting could take place without a change in the programs." (OPC BR 4) SACE does not express a belief on the likelihood of an opt-out resulting in cost shifting.

Recovery of Administrative Costs

Table 3-3 shows Gulf's projected expenses from implementing an opt-out provision. Gulf notes the reasons for the increased administrative costs include its estimate of the need to acquire a customer tracking system, generate enrollment forms, create processes and documentation regarding an opt-out program, and verify energy and demand savings from customers. (EXH 32, Bates 190-191)

Table 3-3
Projected Administrative Expenses - Gulf

One Time Expenses		Annual Ongoing Expenses	
Low Range	High Range	Low Range	High Range
\$250,000	\$400,000	\$100,000	\$180,000

Source: EXH 32, Bates 192

Wal-Mart witness Baker questions whether administrative costs will increase due to an opt-out provision. Witness Baker states, "Wal-Mart does have serious questions about whether the administrative costs would increase or decrease because there would be less…data to have to deal with given that there will be opt-out customers." (TR 76) Witness Baker also stated that Wal-Mart would be willing to pay administrative costs "within reasonable bounds." (TR 76) FIPUG witness Pollack notes there is a significant variance in the administrative cost estimates provided by the four largest IOUs. (TR 549; EXH 24, Bates 90; EXH 27, Bates 122; EXH 29, Bates 140; EXH 32, Bates 192)

FPL expects billing system changes through "identification of ECCR opt-out customers and the creation of additional charge(s) in the rates and billing tables; new charge(s) to be added to all billing screens, data warehouse, rate and revenue report, and other financial reports…." (EXH 24, Bates 89)

DEF expects an opt-out option to create new administrative costs. These costs include determining eligibility by listing accounts, analyzing energy audit results, and reviewing the certifications of a license engineer or certified energy manager. (EXH 27, Bates 112) DEF also expects to inspect a sample of the facilities and track costs attributable to the opt-out program as a result of implementation. (EXH 27, Bates 112-113)

Gulf anticipates that implementing an opt-out policy would lead to ECCR true-up, audit, and projection filing changes. This would include FEECA filing changes through modified ECCR schedules and identification of impacts of opt-out customers on Gulf's DSM program accomplishments. (EXH 32, Bates 190-191)

It is evident that there will be administrative costs to implement an opt-out provision. These costs will include both up-front costs, such as billing changes, and recurring costs, such as verification that opt-out customers meet the eligibility thresholds. (EXH 27, Bates 112-113) The utilities contend that opt-out customers should pay these administrative costs. (TR 427)

Implementation and DSM Goals

The utilities and the parties are divided as to whether to count energy efficiency savings by opt-out participants toward DSM goals. The utilities contend that such savings should only count if opt-out customer savings pass the RIM and free rider criterion established by the Commission in the most DSM Goals docket. The petitioners believe all savings should be counted. OPC recommends that any savings by opt-out customers be counted only if subject to the same criteria established in the most recent DSM Goals docket.

Wal-Mart suggests that the Commission allow the utilities to count projected or actual energy savings from opt-out customers towards the utilities' DSM goals. (TR 59) Wal-Mart does not list in its testimony or briefs any conditions that should apply to counting the energy savings towards DSM goals. Without running cost-effectiveness tests, Wal-Mart does say that "large customers who have undertaken their own conservation and energy efficiency programs provide these benefits to all customers at no cost to those customers." (TR 47)

FIPUG recommends that the Commission allow the utilities to count energy and demand savings from opt-out customers towards the utilities' DSM goals under the condition that the energy and demand savings are measured and verified. (TR 506, 521, 523, 529) FIPUG states that individual companies, when evaluating an energy efficiency investment, use differing criteria to analyze whether the benefits to the company of investing in energy efficiency exceed the costs. (EXH 19, Bates 5) FIPUG also comments that "eligible opt-out customers...invest based on projected energy efficiency measures and corresponding energy savings." (EXH 20, Bates 17-18)

FPL does not elaborate on conditions that should apply to counting savings towards goals. FPL witness Koch does state "[t]he discussion in the testimony of the Wal-Mart witnesses about its independent implementation of DSM is nothing more than a good illustration of free ridership. Their corporate objectives, as provided in the testimony, appear to require implementation of DSM." (TR 145)

DEF believes a RIM test is a key condition for counting opt-out customers' energy savings towards DSM goals because "when you're talking about an individual customer, they might include costs that wouldn't be included in the RIM test in their evaluation. And they might include benefits that wouldn't be included in the RIM test evaluation." (TR 293) In addition to a RIM test, DEF recommends energy savings have less than a two-year payback. (TR 284-285) DEF also suggests a condition that opt-out customers not count "savings that had been achieved up to five years previously." (TR 297) DEF's witness thinks this condition is reasonable because "the (DSM) goals are prospective. Utilities don't take—don't get to take credit for things that have been done in the past." (TR 297)

TECO is in favor of a two-year payback as a minimum condition to count opt-out customer energy savings towards DSM goals. (TECO BR 12) TECO notes that its DSM programs "are measurable and verifiable...(and) meet the Commission's cost-effectiveness test." (TR 388) In contrast, TECO believes that the energy savings from opt-out proposals are not measurable and verifiable. (TR 388)

TECO also states that customer actions that reduce energy, with little reduction in demand, may not pass a RIM test. (TR 491-492) TECO comments, "Wal-Mart's No. 1 project for energy-efficiency...is they installed 1,657 meters in U.S. stores. Those sub-meters will not pass cost-effectiveness. In fact, it will not pass RIM." (TR 412) TECO believes that cost-effectiveness tests are key because "if the opt-out customers have taken such measures to remain competitive and improve their bottom-lines...such action does not necessarily result in lower costs through the ECCR." (TR 452)

Gulf states that if an opt-out were to occur, the Commission should set conditions for counting goals to "ensure that customer implemented energy efficiency measures produce savings which are cost-effective and reliable (i.e. RIM-passing or some other objective metric)." (Gulf BR 12) In addition to being cost-effective through the RIM test, Gulf also believes opt-out customers' energy savings must be obtainable and able to be verified. (TR 343)

OPC recommends a cost-effectiveness test such as the RIM test to ensure that opt-out customers' energy savings meet the same requirements that the Commission uses to set DSM goals. (OPC BR 8)

TECO witness Deason states that "it is important for all customers, not just opt-out customers, to look for ways to conserve and to take beneficial action where appropriate. If the opt-out customers have taken such measures to remain competitive and improve their bottom-lines, they have certainly acted rationally and appropriately. However, such action does not necessarily result in lower costs through the ECCR." (TR 452)

Rule 25-17.0021(3), F.A.C., Goals for Electric Utilities states "each utility's projection shall reflect consideration of...free riders." The Commission approved the two-year payback methodology in its most recent goals orders as an appropriate mechanism for addressing potential free riders.[14] Conversely, if opt-out energy efficiency savings are not counted towards goals, staff notes that cost shifting may occur between opt-out participants and opt-out non-participants. In this case, utilities would not be expected to experience reduced program costs.

[14] Order No. PSC-14-0696-FOF-EU, issued December 16, 2014, in Dkt. Nos. 130199-EI, 130200-EI, 130201-EI, 130202-EI, 130203-EM, and 130204-EM; In re: Commission review of numeric conservation goals of FPL, Duke, TECO, Gulf, FPUC, JEA, and OUC, pg. 43.

Opt-Out Timing

Wal-Mart recommends that there should be a sufficient time period during which an opt-out account may not have taken benefits under designated energy efficiency programs before opting out. (TR 53) Wal-Mart also recommends that there should be a sufficient amount of time after opting out before a customer can opt into an energy efficiency program. (TR 53)

Wal-Mart's recommendations are a way to address the potential for some customers to game the system by opting out or into energy efficiency programs at will in order to reduce ECCR charges one year while receiving rebates by the utility the next year. FIPUG witness Pollock did not seem to disagree with Wal-Mart's opt-out window proposal, calling it "a little more detailed" and expressing no significant objections to an opt-out window. (TR 534)

Verification of Energy Savings

Wal-Mart's proposed method for verification of energy savings is that "the customer certify to the company (utility) that the customer has either (a) has implemented, within the prior 5 years, EE measures that have reduced the customer's usage, measured in kWh per square foot of space...by a percentage at least as great as the company's (utility's) energy efficiency reductions through its approved EE programs... or (b) has performed an energy audit or analysis within the three year period preceding the customer's opt out request and confirms to the utility, that the customer has either implemented the recommended measures or that the customer has a definite plan to implement qualifying EE programs within 24 months." (TR 53-54)

FIPUG's suggests that savings verification be done by a letter from the opt-out customer to the utility. "In addition to attesting that the customer has determined (as a result of an audit or analysis) that there are no cost-effective energy efficiency measures or has invested in energy efficiency measures, the letter should include a certification of the verifiable power and energy savings. The certification should be signed by a licensed professional engineer or certified energy manager." (TR 516)

FPL states that verification for its Business Custom Incentive program is handled by each customer providing engineering information on kW and kWh savings and the costs to the utility. (TR 152) Then, FPL runs cost-effectiveness tests before handing out rebates. (TR 152)

Duke prefers FIPUG's suggested certification signed by a licensed professional engineer to Wal-Mart's proposal. (TR 239) Duke states that in Duke Energy Ohio, customers can self-certify, but the process is "very rigorous." (TR 273) In Duke Energy South Carolina and North Carolina, Duke must rely upon the customer's attestation of energy savings. (TR 275) However, unlike Florida, South Carolina and North Carolina lack DSM goals. (TR 275) Duke believes a state like Florida with DSM goals should "have a more rigorous requirement for measurement verification from a customer who would elect to opt out." (TR 276)

TECO states that measurement and verification is very important because TECO is accountable to the Commission for annual DSM goals. (TR 402-403) Much like FPL, for TECO's current commercial and industrial DSM rebate program, TECO determines if it needs to "do measurement verification beforehand or...take the word of...customers." (TR 431) Then TECO runs cost-effectiveness tests before approving the project to qualify for the commercial and industrial DSM program. (TR 431) Finally, "after the customer actually does the project, depending on the kW savings, the threshold of it, then (TECO will) issue the check either in one part after 90 days of successful operation, and then the second portion of that check after a year." (TR 431)

Primary Staff Analysis and Conclusion

If the Commission approves primary staff's recommendation in Issue 2, then Issue 3 is moot.

Alternative Staff Analysis and Conclusion

If the Commission determines in Issue 2 to direct the parties to develop and implement an opt-out pilot program, specific implementation items addressed at hearing should be approved as recommended below. Where record support in this case does not provide a sufficient basis for an affirmative decision, a workshop or workshops should be conducted to address remaining implementation details. The following analysis addresses those implementation details and processes. As discussed in the alternative staff analysis to Issue 2, the purpose of the pilot program is to collect data regarding the impact of an opt-out policy on: (1) customer energy and demand savings relative to expected savings under utility-sponsored programs; (2) whether these demand and energy savings can be achieved under the Commission's approved cost-effectiveness methodology; and (3) whether cost shifting occurs and, if so, by how much.

Participation Threshold and Account Aggregation

As shown in Table 3-1, the Wal-Mart proposed opt-out participation threshold of 15 million kWh yields the lowest eligible number of participants for the four largest IOUs. For the purposes of a pilot program, minimizing the number of eligible participants will also minimize total implementation and program administrative costs. Thus, alternative staff recommends that for the purposes of a pilot program, the Wal-Mart recommended 15 million kWh threshold is appropriate.

Table 3-2 shows customer eligibility based on Wal-Mart's proposed account aggregation methodology for both the 15 million kWh energy threshold and FIPUG's proposed 1 MW demand threshold. Account aggregation significantly increases the number of eligible customers. For the purposes of a pilot program, minimizing the number of eligible participants will also minimize total implementation and program administrative costs. Thus, alternative staff recommends that for the purposes of a pilot program, the Wal-Mart 15 million kWh threshold unaggregated is appropriate.

Cost Shifting

Alternative staff believes that customers who are not eligible or elect not to participate in an opt-out program should be held harmless from an opt-out provision. The record reveals that two elements in the design of an opt-out provision are necessary to prevent cost shifting. First, any administrative costs associated with an opt-out provision must be paid by the customers that elect to opt out. Second, savings from opt-out customers must either be counted towards utility DSM goals, or utility DSM goals must be adjusted for the impact of lost conservation from opt-out customers. In its most recent goals Order, the Commission approved goals based on the RIM test coupled with the Participants' Test to ensure that utility-sponsored energy efficiency programs will benefit the general body of ratepayers. Therefore, alternative staff recommends that only those energy efficiency measures that pass RIM and have a minimum two-year pack period be eligible for ECCR opt-out credits.[15]

Recovery of Administrative Costs

In order to protect customers that do not meet the opt-out threshold or elect not to participate, alternative staff recommends that opt-out customers should pay any utility administrative costs associated with implementing and maintaining an opt-out provision. The Commission has a long history of requiring the cost-causer to pay for the increased costs. In this case, the opt-out customers would cause utilities to incur additional costs, which FPL estimates to be between $3.3 million and $7.8 million for one-time costs and $150,000 to $950,000 for annual recurring costs. (EXH 24, Bates 90) TECO estimates one time costs of $140,000 and annual recurring costs of $141,000. (EXH 29, Bates 140) Staff notes that customers who do not opt out receive no benefit from the additional administrative costs that utilities expect to incur to implement an opt-out provision. Alternative staff recommends that to the extent possible, administrative costs associated with implementation of an opt-out program be borne by the opt-out participants.

DSM Goals

Alternative Staff agrees with OPC that any opt-out customer savings that are counted toward goals should be required to meet the same tests required by the Commission in setting goals. (OPC BR 8-9) That is, in order for an opt-out customer to qualify for an offset to its ECCR energy efficiency related costs, the individual customers' investment must meet both the RIM test and the two-year payback criterion. In that way, the savings will count toward the utilities DSM goals as determined by the Commission. Alternative staff also agrees with TECO witness Deason's contention that cost-effective conservation decisions by individual customers may not always result in lower costs through the ECCR. (TR 452) Pursuant to the Commission's recent decision in the approvals of utility demand side management plans, utility sponsored programs that count to DSM goals must be monitorable and verifiable. Thus, alternative staff recommends that energy efficiency investments by opt-out customers must meet the Commission approved RIM test and two-year payback criterion. In addition, in order for opt-out customer savings to count to utility DSM goals the savings must be monitorable and verifiable.[16]

Opt-out Timing and Verification of Savings

Alternative staff believes that record is incomplete regarding an opt-out/opt-in window and any other timing issues. The record is likewise inconclusive relating to the appropriate method for verification of energy savings under an opt-out program. Such details shall be addressed in workshop.

Workshop Framework

As discussed in the alternative staff's recommendation to Issue 2, alternative staff believes a pilot program is appropriate to collect data regarding the impact of an opt-out provision on demand and energy savings and ECCR costs. FIPUG and Wal-Mart have provided suggested criteria and the IOUs have raised the need for additional information to present criteria for the

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[15] Order No. PSC-14-0696-FOF-EU, issued December 16, 2014, in Dkt. Nos. 130199-EI, 130200-EI, 130201-EI, 130202-EI, 130203-EM, and 130204-EM; In re: Commission review of numeric conservation goals of FPL, DEF, TECO, Gulf, FPUC, JEA, and OUC, pg. 13, 24.

[16] Order No. PSC 15-0323-FOF-EG, isssud August 11, 2015, in Dkt. No. 150081-EG, In Re: Petition for approval of demand-side management plan of Tampa Electric Company, p. 4.

Commission's review. Further details can be developed through a staff workshop and through the four largest IOUs' working with the parties. The Commission should direct staff, the IOUs, petitioners, and the other parties to address the implementation details enumerated below, plus any additional details needed to implement an opt-out pilot program. In addition, the Commission should direct the four largest IOUs, within 90 days of the workshop, to file pilot opt-out program standards for Commission review and approval. The resulting proposed opt-out program standards and other necessary implementation details would be subject to Commission approval through the PAA process.

1. As recommended in the alternative recommendation to Issue 1, a topic of the workshop should be the appropriate methodology to identify and separate energy efficiency ECCR costs for opt-out customers. The workshop should also address: (1) the appropriate allocation of common costs, and (2) the identification and treatment of any administrative costs related to an opt-out provision. *The appropriate treatment of these costs within the utilities' ECCR filings was not fully addressed in the petitioners' proposals.*

2. Alternative staff suggests an opt-out pilot program of at least three-years long to capture the timing of the ECCR process, plus time to evaluate the results. *The appropriate length of an opt-out pilot program was not addressed during the hearing.*

3. Eligibility threshold:

    a. Alternative staff recommends that the eligibility threshold should be set at 15 million kWh annual energy usage, as suggested by Wal-Mart. (TR 53) The IOUs provided an estimate that this will result in 287 total eligible customers in the four largest IOUs' territories. (EXH 24, Bates 92-93; EXH 27, Bates 116-117; EXH 29, Bates 143-144; EXH 32, Bates 194-195)

    b. Alternative staff recommends that account aggregation should not be allowed for a pilot program in order to meet the sales threshold. Further, account aggregation for purposes of an opt-out policy appears to violate the Commission's conjunctive billing rule, Rule 25-6102, F.A.C.

4. Counting energy efficiency savings from opt-out customers:

    a. Alternative staff recommends that such savings meet the Commission's required cost-effectiveness criteria from its most recent goal setting order. Approved energy efficiency savings must pass the RIM test and have a payback greater than two years to minimize the number of free riders, as the Commission ordered in its review of the IOUs' most recent conservation goals.[17]

    b. Alternative staff recommends that savings be measurable and be verified by the utility, which can include information provided by an independent engineer

[17] Order No. PSC-14-0696-FOF-EU, issued December 16, 2014, in Dkt. Nos. 130199-EI, 130200-EI, 130201-EI, 130202-EI, 130203-EM, and 130204-EM; In re: Commission review of numeric conservation goals of FPL, DEF, TECO, Gulf, FPUC, JEA, and OUC, pg. 43.

contracted by the customer. *The details of appropriate evaluation, measurement, and verification were not addressed in the hearing.*

5. Alternative staff recommends that any reasonable and prudent administrative costs associated with implementing an opt-out provision should be recovered from opt-out customers. Evidence was presented to support opt-out customers paying reasonable administrative costs relating to an opt-out provision.

6. As discussed previously, alternative staff believes the participating opt-out customers should continue to pay the entire ECCR charge throughout each year of the pilot program. *This item was not addressed during the hearing.*

7. Alternative staff suggests as a framework that at the end of each year, opt-out customers could receive a refund/credit for a portion of ECCR charges, capped at the energy efficiency program-related ECCR charges minus any administrative costs. To receive a refund/credit, each participating customer would be required to provide documentation to its IOU of the qualified energy efficiency investments made during the year. *This process was not addressed during the hearing.*

8. Alternative staff believes it is appropriate for utilities to consider an opt-in window, i.e., a specified time period in which interested customers must indicate they wish to participate in the pilot program. Wal-Mart addressed an opt-in window as well as the ways to prevent gaming of an opt-out provision during the hearing. (TR 53) *Alternative staff does not believe the record is sufficient to make a recommendation on an opt-in/opt-out window and suggests further discussion of this concept at workshop.*

In conlusion, the Commission should direct Commission staff to conduct a workshop(s) to determine any other details necessary to implement an opt-out pilot program. The details include, but are not limited to:

- Methodology to avoid and/or minimize cost shifting
- Methodology to identify and recover administrative costs
- Methodology for evaluation, measurement, and verification of opt-out savings
- Appropriate time duration of pilot program
- Appropriate methodology to identify energy efficiency program-related costs in the ECCR clause for the purpose of calculating the opt-out customer's refund cap.
- Necessary data and reporting to facilitate evaluation of the pilot program.

Issue 4: Should this docket be closed?

Recommendation: If staff's primary recommendation in Issue 2 is approved, the docket should be closed after the time for filing an appeal has run. If the Commission denies staff's primary recommendation in Issue 2, this docket should remain open pending further Commission action.

Staff Analysis: The docket should be closed 32 days after issuance of the order, to allow the time for filing an appeal to run. If the Commission denies staff's primary recommendation in Issue 2, this docket should remain open pending further Commission action.

Comparison of Petitioners' Proposals

	Wal-Mart	FIPUG
Basic Proposal – Energy Efficiency Programs	Would allow customers that meet defined criteria and satisfy their EE responsibilities to opt out of participating in utility-sponsored EE programs. These customers would be exempt from paying costs associated with EE programs through the ECCR charge.	Would allow certain customers that have implemented (or plan to implement) EE measures to be exempt from paying ECCR charges for the costs associated with the EE services the utilities provide.
Basic Proposal – Demand Response Programs	Customers that elect to opt out of utility-sponsored EE programs could still participate in utility-sponsored demand response programs and would pay the associated demand response ECCR charges.	Customers that elect to opt out of utility-sponsored EE programs could still participate in utility-sponsored demand response programs and would pay the ECCR charges associated with demand response programs.
EE Commitments	Customer must certify that it: (1) has implemented within the prior 5 years, EE measures that have reduced the customer's usage by percentage at least as great as utility's EE programs, or (2) has performed an energy audit within the previous 3 years and has implemented the recommended measures or has a plan to do so within 2 years.	Customer must provide a letter to utility stating that the customer has invested (or intends to invest) in EE or has conducted an energy audit or analysis determining that there are no cost-effective EE measures.
Eligibility Threshold	Customer energy usage of 15 million kWhs per year	Non-residential customers with demand of at least 1 MW
Account Aggregation	Yes. Across all eligible accounts, meters, or service locations within each utility's service territory	Yes. Provided that each of the aggregated facilities is located in the utility's service area and under common ownership and operation.
Other Criteria	Eligible account may not have taken benefits under EE programs within 2 years before (or 2 years after) the opt-out period	Opt-out letter has a term of not less than 3 years.

Sources: TR 46, 51, 53, 54, 505, 506, 514-516