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Commission Conference Agenda
June 18, 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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Office of Telecommunications (S. Deas, C. Williams)
Office of the General Counsel (K. Young)

RE: Application for Certificate of Authority to Provide Telecommunications Service

AGENDA: 6/18/2015 - Consent Agenda - Proposed Agency Action - Interested Persons May Participate

SPECIAL INSTRUCTIONS: None

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

DOCKET NO.	COMPANY NAME	CERT. NO.
150118-TX	INNOVATIVE TECH PROS, CORP D/B/A INNOVATIVE TECH PROS	8873
140211-TX	Discount CLEC Services Corporation	8867

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

Item 2

State of Florida

Public Service Commission

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

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

DATE: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Office of Telecommunications (Beard)
Division of Economics (Earnhart)
Office of the General Counsel (Hopkins)

RE: Docket No. 150095-TX – Bankruptcy cancellation by Florida Public Service Commission of CLEC Certificate No. 8518, issued to Tennessee Telephone Service, LLC d/b/a Freedom Communications USA, LLC, effective July 15, 2014.

Docket No. 150096-TX – Bankruptcy cancellation by Florida Public Service Commission of CLEC Certificate No. 8168 issued to Terra Telecommunications Corp., effective September 30, 2014.

Docket No. 150097-TX – Bankruptcy cancellation by Florida Public Service Commission of CLEC Certificate No. 8703 issued to StarVox Communications, Inc., effective January 28, 2014.

AGENDA: 06/18/15 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Discussion of Issues

Issue 1: Should the Florida Public Service Commission (FPSC or the Commission) cancel Tennessee Telephone Service, LLC d/b/a Freedom Communications USA, LLC (Tennessee

Telephone), Terra Telecommunications Corp., (Terra Corp.) and StarVox Communications, Inc.'s (StarVox) competitive local exchange telecommunications company (CLEC) certificates, service schedules, and mark each company's name inactive in the Master Commission Directory (MCD) on its own motion effective the date each company's Chapter 7 Bankruptcy case terminated; direct the Division of Administrative and Information Technology Services (AIT) Technology Services to write-off any statutory late payment charges or penalty and interest instead of requesting collection services; and require the companies to immediately cease and desist providing telecommunications services in Florida?

Recommendation: Yes, each entity's CLEC certificate and service schedule should be cancelled and each company's name should be marked inactive in the MCD on the Commission's own motion due to bankruptcy as listed on Attachment A. Also AIT should write off any unpaid statutory late payment charges, or penalty and interest instead of requesting collection service. The companies should immediately cease and desist providing telecommunications services in Florida. (Beard, Hopkins)

Staff Analysis: See attached proposed Order.

Issue 2: Should these dockets be closed?

Recommendation: Yes, these dockets should be closed if no protest is filed upon issuance of a Consummating Order. (Hopkins)

Staff Analysis: The Order issued from this recommendation will become final upon issuance of a Consummating Order, unless a person whose substantial interests are affected by the Commission's decisions files a protest within 21 days of the issuance of a Proposed Agency Action Order. A protest in one docket should not prevent the action in a separate docket from becoming final. These dockets should then be closed upon issuance of a Consummating Order.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Bankruptcy cancellation by Florida Public Service Commission of CLEC Certificate No. 8518, issued to Tennessee Telephone Service, LLC d/b/a Freedom Communications USA, LLC, effective July 15, 2014.	DOCKET NO. 150095-TX
In re: Bankruptcy cancellation by Florida Public Service Commission of CLEC Certificate No. 8168 issued to Terra Telecommunications Corp., effective September 30, 2014.	DOCKET NO. 150096-TX
In re: Bankruptcy cancellation by Florida Public Service Commission of CLEC Certificate No. 8703 issued to StarVox Communications, Inc., effective January 28, 2014.	DOCKET NO. 150097-TX ORDER NO. ISSUED:

The following Commissioners participated in the disposition of this matter:

ART GRAHAM, Chairman
LISA POLAK EDGAR
RONALD A. BRISÉ
JULIE I. BROWN
JIMMY PATRONIS

NOTICE OF PROPOSED AGENCY ACTION
ORDER CANCELLING COMPETITIVE LOCAL EXCHANGE TELECOMMUNICATIONS COMPANY CERTIFICATES AND SERVICE SCHEDULES DUE TO BANKRUPTCY ON THE COMMISSION'S OWN MOTION

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

Tennessee Telephone Service, LLC d/b/a Freedom Communications USA, LLC (Tennessee Telephone) currently holds competitive local exchange telecommunications services (CLEC) Certificate No. 8518, issued by the Commission on October 11, 2004. Terra Telecommunications Corp. (Terra Corp.) currently holds CLEC Certificate No. 8168, issued by the Commission on August 19, 2002. StarVox Communications, Inc. (StarVox), currently holds CLEC Certificate No. 8703, issued by the Commission on December 14, 2007.

Pursuant to Section 364.336, Florida Statutes (F.S.), telecommunications companies must pay a minimum annual Regulatory Assessment Fee (RAF) if the certificate was active during any portion of the calendar year and provides for late payment charges as outlined in Section 350.113, F.S., for any delinquent amounts.

Pursuant to 11 U.S.C. § 362 (b)(4) of the US Bankruptcy Code, the filing of a petition for bankruptcy relief acts as an automatic stay that enjoins a governmental entity from exercising its regulatory authority to collect a pre-petition debt. Additionally, in any bankruptcy liquidation or reorganization, secured creditors are given the highest priority in the distribution and, normally, receive all of the distributed assets. RAFs, late payment charges, and penalties owed by a company to this Commission, as well as monetary settlements of cases resolving issues of failure to pay such fees, are not secured debts and, as a practical matter, are uncollectible in a bankruptcy proceeding where liquidation occurs. Therefore, this Commission would be prevented from collecting the RAFs owed by these companies, and from assessing and collecting a penalty for failure to pay the fees.

Our staff monitor companies that have previously filed for bankruptcy protection to further attempt collection of the past due RAFs. Monitoring is conducted using internet-based Public Access to Court Electronic Records (PACER). In many cases, companies under bankruptcy protection discontinue providing telecommunications services and close their operations, however, our staff are not able to take action to remove these companies from our Master Commission Directory (MCD) until the bankruptcy case is closed or permission to cancel is obtained from the bankruptcy court.

PACER indicates that Tennessee Telephone, filed for Chapter 7 bankruptcy protection in the US Bankruptcy Court – Middle District of Texas, Austin Division on August 4, 2010. The case was closed on July 15, 2014. Our staff researched the Florida Department of State, Division of Corporations' records, which show that the company's last Annual Report was filed on April 28, 2010, and its corporate status was subsequently revoked on September 23, 2011. Our staff also researched the Federal Communications Commission's (FCC) records and found a Form 499 Filer record from April 1, 2011. There was also a statement that read "while the company still exists it is no longer providing services as of October 31, 2010." Due to the company's Chapter 7 bankruptcy filing in 2010, the company did not accrue RAF charges from 2010-2014. However, the company does have outstanding RAF charges pending for the years 2009 and penalty and interest for a total amount of $996.00 ($600.00 in RAF charges and $150.00 in penalties and $246.00 in interest) that need to be requested to be to be written off.

PACER indicates that Terra Corp. filed for Chapter 7 bankruptcy protection in the Federal Court of Miami on February 22, 2005. The case was closed on September 30, 2014. Our staff researched the Florida Department of State, Division of Corporations' records, which showed that the company's last Annual Report was filed on February 4, 2004, and its corporate status was subsequently revoked on September 16, 2005. Our staff also researched the FCC records and found a Form 499 Filer record from April 1, 2004. There was also a statement that while the company still exists, it is no longer active as of July 15, 2005. Due to the company's Chapter 7 bankruptcy filing in 2005, the company did not accrue RAFs from 2005-2014 or incur penalties and interest.

PACER indicates that StarVox filed for Chapter 7 bankruptcy protection in the Northern District of California on March 26, 2008. The case was closed on January 28, 2014. Our staff researched the Florida Department of State, Division of Corporations' records, which showed that the company's last Annual Report was filed on April 30, 2007, and its corporate status was subsequently revoked on September 26, 2008. Our staff also researched the FCC's records and found a Form 499 record of the Chapter 7 bankruptcy protection and a statement the company was no longer active as of March 26, 2008. Due to the company's Chapter 7 bankruptcy filing in 2005, the company did not accrue Regulatory Assessment Fees from 2005-2014 or incur penalties and interest.

Although these companies' bankruptcy cases have closed, it appears that they are no longer providing service in Florida and no longer exist. We are vested with jurisdiction over this matter pursuant to Sections 364.02, 364.336, and 364.285, F.S.

Accordingly, we shall cancel Tennessee Telephone CLEC Certificate No. 8518, service schedules, and mark it inactive in the MCD on this Commission's own motion, effective July 15, 2014, and we shall cancel Terra Corp.'s CLEC Certificate No. 8168, service schedules, and mark it inactive in the MCD on this Commission's own motion, effective September 30, 2014, and we shall cancel StarVox's CLEC Certificate No. 8703, service schedules, and mark it inactive in the MCD on this Commission's own motion, effective January 28, 2014. In addition, any unpaid statutory late payment charges, or penalty and interest shall not be sent to the Florida Department of Financial Services for collection, and permission for this Commission to write off the uncollectible amount shall be requested.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Tennessee Telephone Service, LLC d/b/a Freedom Communications USA, LLC's CLEC Certificate No. 8518 and service schedules are cancelled and its name marked inactive in the MCD, effective July 15, 2014. It is further

ORDERED by the Florida Public Service Commission that Terra Telecommunications Corp.'s CLEC Certificate No. 8168 and service schedules are cancelled and its name its name marked inactive in the MCD, effective September 30, 2014. It is further

ORDERED by the Florida Public Service Commission that StarVox Communications, Inc.'s CLEC Certificate No. 8703 and service schedules are cancelled and its name marked inactive in the MCD, effective January 28, 2014. It is further

ORDERED that each entity's unpaid statutory late payment charges, or penalty and interest, shall not be sent to the Department of Financial Services for collection. The Division of Administrative and Information Technology Services shall request permission to write-off the uncollectible amount. It is further

ORDERED that if Tennessee Telephone Service, LLC d/b/a Freedom Communications USA, LLC's, Terra Telecommunications Corp., and StarVox Communications, Inc.'s respective CLEC Certificates and service schedules are cancelled and their names marked inactive in the MCD in accordance with this Order, each entity shall immediately cease and desist providing telecommunications service in Florida. It is further

ORDERED that any protest to the action proposed herein shall specify the entity or entities to which it applies. It is further

ORDERED that if a protest to this Order is filed, the protest shall not prevent the action proposed herein from becoming final with regard to the remaining entities listed in this Order. It is further

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, F.A.C., is received by the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this docket shall be closed.

By ORDER of the Florida Public Service Commission this _____ day of _____, _____.

CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

SMH

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing that is available under Section 120.57, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

The action proposed herein is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on _____.

In the absence of such a petition, this order shall become final and effective upon the issuance of a Consummating Order.

Any objection or protest filed in this/these docket(s) before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

Item 3

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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (Maurey) ALM
Office of the General Counsel (Barrera) JSC

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

AGENDA: 06/18/15 – Regular Agenda – Post-Hearing Decision – Participation is Limited to Commissioners and Staff

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On June 25, 2014, Florida Power & Light Company (FPL or Company) petitioned the Commission for a determination that it is 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 is eligible for recovery through the Fuel Clause (Petition). FPL further requested that the Commission establish guidelines under which FPL could participate in future gas reserve projects without prior Commission approval and recover the costs through the Fuel Clause, subject to the Commission's established process for reviewing fuel-related transactions in Fuel Clause proceedings. FPL requested that the Commission consider these elements of its Petition at the Commission's October 22-24, 2014 Fuel Clause hearing.

On August 22, 2014, by Order No. PSC-14-0439-PCO-EI, the gas reserve issues were bifurcated from the Fuel Clause proceeding.[1] The gas reserve issues were scheduled to be heard at a separate hearing on December 1-2, 2014.

On August 22, 2014, the Office of Public Counsel (OPC) filed a Motion to Dismiss FPL's Petition on the grounds that the Commission does not have subject matter jurisdiction. On August 29, 2014, FPL filed its response in opposition to OPC's Motion. The Commission heard oral argument on the Motion to Dismiss at the Commission Conference on November 25, 2014. On December 17, 2014, the Commission issued Order No. PSC-14-0697-PCO-EI denying OPC's Motion.[2]

The hearing was held on December 1-2, 2014, at which FPL, OPC, the Florida Industrial Power Users Group (FIPUG), and the Florida Retail Federation (FRF) all participated. At the conclusion of the hearing, the Commission scheduled Issues 1, 2, 3, 6, and 8 related to the Woodford Project for consideration at the December 18, 2014 Commission Conference. The Commission deferred consideration of Issues 4, 5, 7, and 9 related to FPL's request for approval of investment guidelines to a future Commission Conference.

The Commission voted on the Woodford Project issues at the December 18, 2014 Commission Conference. By Order No. PSC-15-0038-FOF-EI issued January 12, 2015, the Commission found the Woodford Project in the public interest and the costs recoverable through the Fuel Clause.[3]

On January 15, 2015, OPC filed a Notice of Appeal in the Florida Supreme Court of Commission Order No. PSC-14-0697-PCO-EI, denying OPC's Motion to Dismiss for lack of subject matter jurisdiction (Florida Supreme Court Case No. SC15-95). On January 20, 2015, OPC filed a Notice of Appeal in the Florida Supreme Court of Commission Order No. PSC-15-0038-FOF-EI, approving the Woodford Project for cost recovery through the Fuel Clause (Florida Supreme Court Case No. SC15-113). Also on January 20, 2015, OPC filed a Notice of Appeal in the Florida Supreme Court of Commission Order No. PSC-14-0701-FOF-EI, approving the fuel and purchased power cost recovery factors for all Florida investor-owned electric utilities, including FPL (Florida Supreme Court Case No. SC15-115).[4] On February 10, 2015, FIPUG filed a Notice of Appeal in the Florida Supreme Court of Commission Order No. PSC-15-0038-FOF-EI, approving the Woodford Project (Florida Supreme Court Case No. SC15-274). 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). Also on March 30, the Florida Supreme Court dismissed OPC's petition for a writ of prohibition seeking to restrain

[1] See Order No. PSC-14-0439-PCO-EI, issued August 22, 2014, in Docket No. 140001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
[2] See Order No. PSC-14-0697-PCO-EI, issued December 17, 2014, in Docket No. 140001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
[3] See 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.
[4] See Order No. PSC-14-0701-FOF-EI, issued December 19, 2014, in Docket No. 140001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor. Order No. PSC-14-0701-FOF-EI addresses issues not related to the Woodford Project or the proposed Guidelines.

the Commission from proceeding on FPL's petition to establish guidelines for FPL's participation in future gas reserve projects and granted the Commission's motion to relinquish jurisdiction authorizing the Commission to continue its proceedings on FPL's Petition.

The parties' post hearing briefs addressing Issues 4, 5, 7, and 9 related to FPL's proposed Guidelines were filed on January 12, 2015. This recommendation addresses these issues.

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.

Discussion of Issues

Issue 4: Do FPL's proposed Guidelines for future capital investments in natural gas exploration and drilling joint ventures satisfy the Commission's criteria for consideration in the fuel cost recovery clause proceeding?

Recommendation: Yes. (Maurey)

Position of the Parties

FPL: Yes. The investments also would provide a physical hedge against natural gas price volatility. The Commission historically has allowed hedging costs to be recovered through the fuel clause. Additionally, FPL's proposed Guidelines require that gas reserves investments be projected to produce fuel savings for FPL's customers. The Commission has a long history of allowing cost recovery through the fuel clause for investments that result in fuel savings.

OPC: No. FPL's Proposed Guidelines violate the guiding principles and policy decisions announced by the Commission in Order No. 14546 and its progeny. It further violates the "case-by-case" prudence review required by these orders by requesting presumptive eligibility for recovery and prudence of every project that purports to "satisfy" the Guidelines. FPL is attempting to increase its rate base in unregulated, non-jurisdictional investments, outside the traditional rate-regulated electric monopoly utility functions of "generation, transmission, and distribution" expressly recognized in statute. If approved, it would open the door for every other investor owned utility to seek a risk-free way to expand rate base without a determination of need and without much scrutiny. Further, FPL's proposed investments in gas reserves projects: (1) is not hedging; (2) does not satisfy the definition of hedging as established by the Commission's hedging orders and hedging policy and (3) will not reduce fuel price volatility to the *benefit* of FPL's customers. Any fuel price volatility experienced by the customers is already, and effectively, mitigated by the annual resetting of the fuel factor in the Fuel Clause. That irrefutable fact belies the truth of FPL's assertion that fuel price volatility is something that must be mitigated through speculative, and risky natural gas reserves investments.

FIPUG: No. FIPUG joins and adopts the arguments of the Office of Public Counsel.

Staff Analysis: By Order No. PSC-15-0038-FOF-EI, the Commission found that an investment in a working interest in a natural gas reserve project (the Woodford Project), in the manner described in FPL's Petition and evidence on the record, is expected to produce customer benefits and is in the public interest.[5] The Commission also found that the revenue requirement associated with the investment in the Woodford Project is eligible for recovery through the Fuel Clause.

FPL's proposed Guidelines do not represent an actual cost that would be requested for recovery through the Fuel Clause. Instead, evidence in the record indicates that the proposed Guidelines are a set of parameters by which other, similar projects will be evaluated and assessed

[5] See 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, p. 6.

for consideration as possible candidates for future investment. (TR 123; FPL BR 5) The Commission has found that the revenue requirement associated with the Woodford Project is eligible for recovery through the Fuel Clause. If guidelines are approved, FPL's request for recovery of costs for similar investments approved by the Commission under the guidelines would satisfy the criteria for consideration in the fuel cost recovery clause proceeding. Whether FPL's proposed Guidelines, modified guidelines, or no guidelines are appropriate for approval at this time is the subject of Issue 5.

Issue 5: If the Commission answers Issue 4 in the affirmative, should the Commission approve FPL's proposed criteria?

Recommendation: No. Due to the magnitude of the investments, the length of the commitments required, and the presumption of prudence that would attach, staff recommends any requests for approval of future gas reserve projects be considered on a case-by-case basis. It would be appropriate to have more experience with this form of investment and the magnitude of costs requested for recovery before the Commission approves guidelines for the proposed investment program with prudence attached. However, if the Commission finds it is appropriate to establish guidelines at this time, staff recommends the modifications attached to the end of this recommendation as Attachment A. (Maurey)

Position of the Parties

FPL: Yes. FPL's proposed Guidelines strike an appropriate balance the FPL's desire to secure low-cost, stable fuel sources for customers, the need to make prompt decisions in a competitive market, and the need to maintain regulatory oversight for the ongoing protection of customers. As proposed, the guidelines allow FPL to consummate a transaction when an agreement has been reached that meets the Guidelines, without having to wait on the normal several month-long Commission approval process that likely would foreclose FPL from participating in many potentially valuable gas reserves projects. The Guidelines are appropriately structured to limit the total dollar amount of FPL's gas reserves investments and to ensure both that the investments are projected to produce fuel savings for customers and that they are for the types of reserves that are most useful for FPL's customers. Specifically, the Guidelines cover the scope of FPL's project participation as a percentage of average daily burn, as well as on an annual capital expenditure basis. They also describe how the deals will be evaluated against FPL's then-current forecast of natural gas prices. Finally, the Guidelines discuss the composition of gas reserves that FPL can pursue. While the parameters proposed by FPL are reasonable, the Company would not object to modifications by the Commission so long as the approved guidelines satisfy three gas reserves objectives.

OPC: No. FPL's Proposed Guidelines are one-sided, and completely favor FPL and its shareholders at the expense of FPL's 4.5 million customers. They should be rejected outright. While OPC maintains the Commission does not have subject matter jurisdiction to approve any gas reserves investments, let alone the Proposed Guidelines, OPC believes that the Commission's staff's suggested 50/50 sharing of risk and rewards or OPC Witness Ramas' hypothetical suggestion "up to the market price of gas" are much better than what FPL has proposed. Either option would put some of FPL's "skin into the game" and would align FPL customer and shareholder incentives. FPL would be motivated under those scenarios to perform a level of due diligence not currently required by the Proposed Guidelines. However, OPC maintains that the better regulatory policy decision would be to reject FPL's Proposed Guidelines.

FIPUG: No. Consistent with section 120.54, Florida Statutes, the Commission should engage in rulemaking to adopt any policy statements regarding the exploration and production of oil and natural gas.

Staff Analysis: FPL's request for approval of guidelines for investment in natural gas reserve projects has significant policy implications. (TR 739-740, 947-948, 961, 965) The program of preapproved investment contemplated under the proposed Guidelines has never been done before in Florida or by any electric utility in the country. (TR 208, 388, 593, 644, 651, 904, 916) In addition, it would represent the first time non-regulated investments would be recovered through regulated rates with a predetermination of prudence. (TR 739-740, 947-948, 961, 965)

PARTIES' ARGUMENTS

FPL

FPL witness Forest testified that the Woodford Project approved by Order No. PSC-15-0038-FOF-EI represents an example of just one agreement in a broad market. (TR 119) FPL has proposed the Commission establish guidelines under which FPL could participate in future gas reserve projects and recover the associated costs through the Fuel Clause without prior Commission approval, subject to the Commission's established process for reviewing fuel-related transactions in the Fuel Clause proceeding. (TR 88) Due to the amount of the investment and the length of the commitments required, witness Forest testified that FPL must have a presumption of prudence from the Commission before proceeding. (TR 88, 973)

FPL has proposed a set of Guidelines that it contends provides a framework to allow FPL to consummate other transactions in the future that meet these Guidelines, without having to seek prior approval from the Commission. (TR 121) As explained by witness Forest, most counterparties to date have been unwilling to wait the length of time necessary for regulatory approval in order to execute an agreement. (TR 121) Without assurance from the Commission that it concurs with FPL's approach, witness Forest testified that FPL cannot justify making such significant financial commitments. (TR 88)

Witness Foster testified that adoption of guidelines would be consistent with how the Commission administered FPL's financial hedging program. (TR 122) He noted how the Commission worked with FPL and the other investor-owned utilities (IOUs) in a collaborative effort to develop and implement a process and eventually guidelines for what should and should not be part of the financial hedging programs. (TR 122) Similar to the guidelines adopted for financial hedging programs, he suggested the Commission could establish a framework whereby the Company could enter into several transactions that were within a range of predetermined guidelines. Finally, witness Foster testified that, similar to the guidelines set forth for the financial hedging programs, "the Commission should acknowledge that there are potential drilling/production risks with pursuing gas assets and as long as the transaction was within the guidelines, it cannot be deemed imprudent based on the results." (TR 123; FPL BR 7)

Witness Foster testified that the proposed Guidelines will enable FPL to act in real time to secure gas reserve projects for the benefit of FPL customers. However, he stated that the drilling and production sector of the natural gas industry is not accustomed to waiting months for a potential counter-party to obtain regulatory approval to decide whether to close on a transaction. Witness Foster testified that without the presumption of prudence provided by FPL's proposed Guidelines, FPL will not be able to bring such projects to fruition for the benefit of its customers. (TR 973, 1037)

In its brief, FPL argued that it would not object in principle if the Commission in its discretion prefers to "test the waters" by initially adopting guidelines that scale down the size of the allowed transactions or narrowed the scope of eligible investments. (FPL BR 13-14) However, FPL argued that approval of guidelines is essential in order for the Company to deliver the benefits to customers FPL believes are available through its proposed program of investment in gas reserve projects. (FPL BR 22)

OPC

OPC argued that the Commission lacks subject matter jurisdiction to approve for recovery from customers the costs associated with investments in the non-regulated natural gas drilling and production industry. (OPC BR 1) In its brief, OPC argued that approval of the proposed Guidelines would impermissibly shift the investment risks from FPL's shareholders to its customers and would represent a new way of reducing shareholder risk and enhancing shareholder returns. (TR 558; OPC BR 1-2)

OPC witness Lawson testified that FPL's proposal in this docket reflects FPL's decision to diversify into a separate, non-regulated industry. (TR 686, 731) The Company is requesting the Commission expand the traditional Fuel Clause so that FPL can import investments in gas reserve projects and require customers bear the investment risk associated with natural gas drilling and production. (TR 680) Witness Lawson testified that the end result of FPL's proposal would be that the risk of natural gas drilling and production typically borne by market participants such as PetroQuest Energy, Inc. (PetroQuest), would be shifted by PetroQuest through FPL and/or its non-regulated affiliate directly to FPL's customers. (TR 725-726)

Witness Lawson argued that FPL's proposed Guidelines are one-sided to the benefit of FPL and are not fair or equitable to its customers. (TR 737-738) He noted that FPL's proposed Guidelines only require the projection of fuel savings for customers at a point in time, but does not guarantee any savings. (TR 692) In contrast, if FPL's proposed Guidelines and the presumption of prudence that would attach are approved, the Company would be assured of earning its midpoint return on equity (ROE) on these investments regardless of the outcome of the investment or whether any fuel savings actually materialized as long as the Company demonstrated that the investment complied with the Guidelines at the time the investment was entered. (TR 161, 693-694, 736-738; OPC BR 7)

With respect to FPL's testimony regarding the need for the Company to have the ability to act quickly to take advantage of these investment opportunities, witness Lawson testified that the Commission should take caution from FPL's claim. (TR 739) He posited that "if gas reserve market participants must act within a month or two window as market prices fluctuate, why would this Commission or any other regulator consider the Woodford Project or any future gas reserve investment where the economic viability rests primarily on a 50-year forecast of market prices, and more than a two-month delay may change the economics of the deal?" (TR 739)

Finally, witness Lawson testified that the true purpose of FPL's proposed gas reserve investment program is a new earnings platform for the Company and NextEra Energy, Inc.

(NextEra). (TR 694, 793) If the proposed Guidelines are approved as filed, he argued that FPL would be able to grow rate base and earnings through the Fuel Clause without regard to whether the customers received any benefit from the investments. (TR 694, 741) In conclusion, witness Lawson recommended that FPL's proposed Guidelines be denied and that any future gas reserve projects be addressed on a case-by-case basis. (TR 738-739)

FIPUG

FIPUG opposes FPL's efforts to have its customers fund natural gas drilling and production ventures as contemplated in FPL's proposed Guidelines. (FIPUG BR 1-2) In its brief, FIPUG argued that policy is set by the Legislature and that the Commission should not implement policy by adopting "guidelines." (FIPUG BR 2) FIPUG recommended that the Commission not act on FPL's proposed Guidelines but instead hold workshops or other proceedings with wider participation before implementing "policies governing future investor-owned utility proposed and ratepayer-funded oil and gas exploration/drilling/production ventures." (FIPUG BR 7, 15)

FIPUG witness Pollock testified that the Commission should reject FPL's proposed Guidelines. (TR 644) He argued that FPL's proposed Guidelines do not address the sharing of risk between FPL and its customers nor do they impose any obligation on FPL to demonstrate that its customers have benefitted from investments in gas reserve projects. (TR 655-656) If FPL's proposed Guidelines are approved as filed, witness Pollock testified that FPL would recover its investment and earn its mid-point ROE irrespective of whether FPL's customers receive any benefit. (TR 648)

Witness Pollock also raised other concerns regarding FPL's proposal. Noting that approval of FPL's Guidelines would be the first time a regulated electric utility would be permitted to recover non-regulated investments through regulated rates, he cautioned the Commission regarding the significant policy implications of combining regulated and non-regulated investments in an integrated utility. (TR 651) He also expressed concern regarding the expansion of rate base through the Fuel Clause. While the benefits to FPL under its proposal are apparent, he argued the proposal holds only marginal or questionable benefits for FPL's customers. (TR 648, 651) In conclusion, witness Pollock recommended that FPL's proposed Guidelines be denied. (TR 658)

ANALYSIS OF PARTIES' ARGUMENTS

FPL's proposed Guidelines were sponsored by and attached to witness Forest's direct testimony. (TR 123; EXH 10). While initially filed under confidential treatment, at FPL's request, the document was later declassified.[6] Generally, the Guidelines outline the parameters under which FPL proposes to enter future agreements for gas reserve projects. The Guidelines include provisions which describe the limits to FPL's participation in projects. Namely, the provisions specify the percentage of average daily burn the aggregate output from the projects may represent, the composition of the natural gas (percentage of methane versus natural gas liquids) that FPL can pursue, and the maximum annual capital expenditure FPL may invest in

[6] See Document No. 06432-14 in Docket No. 140001-EI.

these projects. (TR 123; EXH 10) Finally, the Guidelines specify the terms under which any agreements FPL enters will be evaluated by the Commission to determine if the investments are consistent with the Guidelines. (TR 123; EXH 10; FPL BR 6-7)

In its Petition, FPL requested that, similar to the financial hedging guidelines, the Commission establish a framework whereby the Company could enter into several transactions if they are within a range of predetermined terms/guidelines. (TR 84-85, 121, 909; FPL BR 18-19) FPL witness Forest further explained that adopting guidelines for gas reserve investments would be consistent with how the Commission has administered the financial hedging programs of the IOUs. (TR 122)

While the financial hedging program and the proposed physical hedging program do share certain similarities, there are also certain differences between the two programs as well. (TR 115, 122-123, 619-620) First and foremost are the duration of the financial exposure and the form of cost recovery granted. The financial hedging program involves the recovery of incremental operation and maintenance (O&M) costs through the Fuel Clause associated with short-term financial instruments (12-24 months). (TR 85) The proposed physical hedging program involves the recovery of incremental O&M costs as well as recovery of a rate of return on capital through the Fuel Clause associated with long-term capital investments (30 years or more). (TR 125, 203; EXH 9)

An additional difference between the two programs is the window of time being proposed for the Commission's consideration of guidelines that will attach prudence to these investments. (TR 901-902) The Commission's initial policy regarding risk management and hedging of fuel prices is embodied in Order No. PSC-02-1484-FOF-EI (Hedging Order).[7] This order approved a settlement agreement, reached between each of the four generating IOUs, FIPUG, and OPC, which established a framework for risk management of fuel procurement by FPL, Florida Power Corporation (now Duke Energy Florida), Tampa Electric Company, and Gulf Power Company.[8] After the issuance of the Hedging Order, each of the four IOUs developed financial hedging programs.

It is important to note the timeline that led to the Commission's adoption of guidelines for the financial hedging program. In approving the settlement agreement, the Hedging Order provided flexibility for each IOU to create the type of risk management program for fuel procurement that it finds most appropriate while allowing the Commission to retain the discretion to evaluate, and the parties the opportunity to address, the prudence of such programs at the appropriate time. Unlike FPL's request for approval of proposed Guidelines in the instant docket, a presumption of prudence did not automatically attach to financial hedging transactions as a result of the framework approved in the Hedging Order issued in 2002.[9] (TR 84-85, 130, 973; FPL BR 7)

[7] See 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.
[8] See Order No. PSC-02-1484-FOF-EI, p.p. 1-2.
[9] See Order No. PSC-02-1484-FOF-EI, p.p. 2,5.

After the IOUs developed their respective financial hedging programs and the Commission gained experience with the companies' practices under the framework established in the Hedging Order, the Commission issued Order No. PSC-08-0667-PAA-EI, which clarified the Hedging Order and provided guidelines for detailed risk management plans.[10] Unlike the instant case which involves only one IOU and a limited number of interested parties, the establishment of guidelines for financial hedging programs was a collaborative effort open to all four IOUs and interested parties.[11] (FPL BR 19) Also unlike the instant case, the Commission had a number of years of actual experience with the IOUs' investment practices and the range of costs they would request for recovery through the Fuel Clause before it considered guidelines with presumptive prudence attached.[12] (TR 130) While a framework for financial hedging was approved in 2002, the guidelines for financial hedging were not approved until 2008.

By Order No. PSC-15-0038-FOF-EI, the Commission found that an investment in a working interest in a natural gas reserve project (the Woodford Project), in the manner described in FPL's Petition and evidence on the record, is expected to produce customer benefits and is in the public interest.[13] The Woodford Project has been described by FPL "as an excellent candidate" for the first gas reserve project. (TR 42). Witness Forest testified that this transaction "is projected to be highly beneficial for FPL's customers" and has an 85 percent probability of producing fuel savings for customers. (TR 114, 333, 1043) The investment in the Woodford Project was initially recorded on the books of FPL's non-regulated affiliate, USG. FPL witness Ousdahl testified that upon a Commission determination that FPL's investment in the Woodford Project is prudent and the costs are recoverable through the Fuel Clause, USG will transfer the investment to FPL at net book value. (TR 354, 376-377) With the approval of the Woodford Project, the Commission has the means to gain meaningful experience regarding precisely how this type of investment will perform over time and a better understanding of the range and magnitude of costs FPL will propose for recovery through the Fuel Clause associated with an investment in a natural gas drilling and production operation. (TR 970-971, 984-985)

Finally, an examination of the specific guidelines, as discussed below, shows that there are a number of questions and concerns surrounding FPL's proposed program of gas reserve investments. The Guidelines proposed by FPL, along with modifications in a type-and-strike format, are attached to the end of this recommendation as Attachment A.

ANALYSIS OF PROPOSED GUIDELINES

In Guideline I.A, FPL has proposed maximum percentages of average daily burn of 15 percent, 20 percent, and 25 percent for 2015, 2016, and 2017, respectively. (EXH 10) In Guideline I.B, FPL has proposed to provide an annual update to this three year window "informing the Commission of the relative percentage of average daily burn the aggregate output of all gas reserve projects represent." (EXH 10) It is unclear from this statement if FPL is

[10] See 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 incentive factor.
[11] See Order No. PSC-08-0667-PAA-EI, p.p. 3-4.
[12] See Order No. PSC-08-0667-PAA-EI, p. 1.
[13] See 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, p. 6.

proposing that the 25 percent level in 2017 will be the ceiling or if this limit will increase in the future. (TR 1059) FPL customers may suffer a high degree of risk exposure associated with these non-regulated investments. (TR 558, 654, 725-726) If guidelines are determined to be appropriate in the future, staff believes the maximum volume as a percentage of average daily burn should be reduced to limit the customers' exposure to this form of non-regulated risk.

In Guideline I.D, FPL has proposed an investment cap of $750 million per year in the aggregate on gas reserve projects over the course of any one calendar year. (TR 976; EXH 10) At this level of investment, FPL could add the equivalent of a new combined cycle power plant to rate base every other year. (TR 278) When asked, FPL's witness was unable to identify what level of investment in gas reserve projects would represent a risk to the Company's on-going utility operations. (TR 279) If guidelines are determined to be appropriate in the future, staff believes such guidelines should limit the customers' exposure to this form of non-regulated risk by capping the allowed annual investment at a more modest level.

Section II of FPL's proposed Guidelines is titled Customer Savings. OPC raised concerns that FPL's proposed program for investing in gas reserve projects is designed more for the benefit of FPL and NextEra shareholders than for FPL customers. (OPC BR 2) NextEra, through its non-regulated subsidiary USG, has been investing in gas reserve projects since 2010. (TR 136-137, 355, 582, 1023) FPL witness Taylor testified that the Woodford Project became available to FPL because USG had already reached its budget limit for investments for the period. (EXH 57, p. 66) However, the Guidelines proposed by FPL are silent on how it will be decided which future gas reserve projects will be recorded on the books of USG and which projects will be recorded on FPL's books. (TR 256-257, 260-261, 306-308; EXH 10)

This Guideline also raises the concern, expressed by both OPC and FIPUG, that these investments are intended more for NextEra's corporate diversification rather than to produce fuel savings for customers or reduce fuel price volatility. (TR 643, 731; OPC BR 34) FPL's proposed Guidelines are silent on the issue of how it will demonstrate that the deals entered on FPL's behalf are as good as or better than the deals entered on NextEra's own account. OPC witness Lawton testified that FPL's "Guideline proposals are one-sided, favoring FPL at every opportunity with no real equity for customers." (TR 738) The Guidelines proposed by FPL do not provide a methodology that ensures transparency nor demonstrates that FPL's customers are receiving the greatest opportunity for fuel savings associated with investments in gas reserve projects. There is no mechanism for reporting the results of all gas reserve projects entered by FPL, USG, and/or any other affiliate or subsidiary of NextEra in a transparent manner and presented on a comparable basis, so that FPL can address the concern that the investments made on behalf of FPL's customers are as good as or better than the gas reserve projects made on NextEra's own account. (TR 260-261; OPC BR 34)

Guideline II.A provides that the Commission's evaluation of the prudence of FPL having entered into a new gas reserve project will be based on a showing that the project is estimated to generate fuel savings for customers on a net present value basis, relying solely on information relative to these Guidelines available to FPL at the time the transaction was entered, including the use of an independent third party reserve engineering report and FPL's standard fuel price forecasting methodology. (EXH 10) The proposed Guidelines grant a presumption of prudence

without holding FPL to the generally accepted standard of what information was reasonably available to the Company at the time it made the decision to invest. (TR 972-973; OPC BR 30) This omission is not appropriate in this instance as the decision to invest is based on a set of assumptions at a single point in time but the presumed benefits for customers are dependent on the outcome of a natural gas drilling and production operation over multiple decades. (TR 268-269, 715, 739)

The proposed Guidelines do not include a requirement for FPL to engage an independent auditor, involve Commission staff in the development of the audit scope, nor the use of subaccounts for purposes of recording FPL's transactions related to gas reserve projects. (FPL BR 17; OPC BR 23) During the hearing, the ability of the Commission to effectively audit gas reserve investments was vigorously debated. With the approval of the Woodford Project, the Commission will have the opportunity to perform audits to determine the actual ease or difficulty of the audit process and will be in a better informed position to assess what terms may be necessary to include in the guidelines at a future time. In addition, if guidelines are approved in the future, such guidelines should be consistent with all mandates specified in Order No. PSC-15-0038-FOF-EI related to the Woodford Project.

The third bullet point under the heading, Section III. Supply Diversity, maintains that FPL intends to transact with a wide range of suppliers to minimize concentration of supply with any one producer and to reduce credit exposure to any one entity. (EXH 10) Staff shares FIPUG's concern regarding counterparty risk of participants in the natural gas drilling and production industry. (FIPUG BR 13) The Guidelines fail to provide measures for minimizing counterparty risk such as a limitation to only transact with producers that are also producers for existing gas reserve projects held by one or more NextEra affiliates or subsidiaries.

Guideline III. A specifies that FPL will only pursue onshore gas reserve projects located in areas that have a well-established history of gas production. (TR 123; EXH 10) FPL witness Taylor testified that the Securities and Exchange Commission (SEC) uses three standard categories for classifying gas reserves for public company reporting. (TR 499) Proved Reserves are those reserves with reasonable certainty (90 percent probability) that the predicted quantity of gas can be commercially recovered under current technical, contractual, economic, and regulatory conditions. (TR 499) Probable Reserves are those reserves with some uncertainty (50 percent probability) that the predicted quantity of gas can be commercially recovered under current technical, contractual, economic, and regulatory conditions. (TR 500) Possible Reserves are those reserves with high uncertainty (10 percent probability) that the predicted quantity of gas can be commercially recovered under current technical, contractual, economic, and regulatory conditions. (TR 500). Witness Taylor testified that "a typical gas reserve investment portfolio would appropriately be comprised of a wide range of projects, including reserves that fall within each of the major SEC categories of Proved, Probable, and Possible." (TR 502)

Despite the stated primary purpose of FPL's proposed gas reserve investment program to secure a physical source of natural gas, FPL's proposed Guidelines are silent on the appropriate or permissible mix of reserves, Proved, Probable, or Possible, that FPL may pursue. (EXH 10) While FPL witness Forest testified that FPL's proposed Guidelines are intended for the Company to pursue proven reserves, he admitted that the guidelines as submitted would not

prohibit exploration or "wildcatting." (TR 1057) If guidelines are determined to be appropriate in the future, staff believes such guidelines should require FPL to focus on those gas reserve projects with the most certainty around production in order to better ensure the program secures a physical source of natural gas. (TR 501)

The final paragraph of FPL's proposed Guidelines offers a means by which the Guidelines could be modified in the future and provides the flexibility for FPL to present gas reserve projects that may deviate from one or more of the Guidelines for consideration for recovery on a case-by-case basis. (TR 1032-1033; EXH 10) However, this final guideline fails to clarify how this requested flexibility will be administered. If guidelines are determined to be appropriate in the future, staff believes further elaboration on how requested modifications to the guidelines or requests for case-by-case consideration will be addressed is required.

Finally, on a macro level, staff believes that the distribution of benefits to FPL and its customers is not equitable under FPL's Guidelines as proposed. The anticipated benefits to the customers, namely, possible fuel savings and a reduction in price volatility, are entirely dependent on the outcome of the underlying investment in natural gas drilling and production and the movement in the market price of natural gas. In addition, these benefits will not be known until many years, perhaps decades, in the future. In contrast, the anticipated benefits to FPL, namely, the opportunity to grow earnings and rate base through the Fuel Clause and the opportunity to recover non-regulated investments through regulated rates, are entirely independent of the aforementioned underlying investment or the movement in the market price of natural gas. In addition, under FPL's proposed Guidelines, the Company's benefits are assured and will be known at the time the investment is made. This disparity in both the timing and assurance of benefits flowing from FPL's proposed investment program should be addressed before guidelines, which would grant presumptive prudence for recovery of non-regulated investments through the Fuel Clause, are approved.

CONCLUSION

Just as FPL cannot justify undertaking such a sizable financial commitment without assurance from the Commission of presumptive prudence, staff cannot recommend approval of guidelines for a new program with such significant policy implications without actual experience of how these non-regulated investments will perform and the magnitude of costs FPL will seek to recover through the Fuel Clause. (TR 964-966) With the approval of the Woodford Project, the Commission has the means to gain meaningful experience regarding precisely how this type of investment will perform over time and a better understanding of the range and magnitude of costs FPL will propose for recovery through the Fuel Clause associated with an investment in a natural gas drilling and production operation. (TR 970-971, 984-985) While staff is not suggesting the Commission necessarily needs seven years of experience as it had before considering guidelines for the financial hedging program, staff does believe it would be appropriate to have more experience with this form of investment and the magnitude of costs requested for recovery before the Commission approves guidelines for the newly proposed investment program with prudence attached.

In addition, staff believes that the distribution of benefits to FPL and its customers is not equitable under FPL's Guidelines as proposed. The anticipated benefits to the customers in the form of fuel savings and a reduction in price volatility are entirely dependent on the outcome of the underlying investment and the movement in the market price of natural gas. In addition, these benefits are not assured and will not be known until years in the future. In contrast, the anticipated benefits to FPL in the form of growing earnings and rate base through the Fuel Clause and the recovery of non-regulated investments through regulated rates are entirely independent of the outcome of the underlying investment or the movement in the market price of natural gas. In addition, under FPL's proposal as filed, the Company's benefits are assured and will be known at the time the investment is made. Therefore, for the reasons outlined above, staff believes it is premature to approve guidelines for the proposed investment program at this time. Staff recommends any requests for approval of future gas reserve projects be considered on a case-by-case basis.

However, if the Commission finds it is appropriate to establish guidelines at this time, staff recommends the Commission consider the modifications attached to the end of this recommendation as Attachment A. While the suggested modifications do not address the inequity in the distribution of benefits discussed above, they may serve to mitigate some of the risk that customers will be exposed to and would add clarity to certain provisions of FPL's proposed Guidelines that were silent on key parameters related to this new investment program.

Issue 7: If the Commission concludes that FPL's petition has merit, should the Commission engage in rulemaking pursuant to Section 120.54, Florida Statutes, and adopt rules addressing gas reserves guidelines and operations rather than adopting the Gas Reserves Guidelines as proposed by FPL?

Recommendation: No. If the Commission adopts guidelines, it is not required to engage in rulemaking. First, the proposed Guidelines are not rules under the definition in Section 120.52(7), F.S. Second, the Commission is exempt from rulemaking pursuant to the provisions of Section 120.80(13)(a), F.S., applicable to cost-recovery clauses, factors, or mechanisms. (Barrera)

Positions of the Parties

FPL: No. Order No. PSC-14-0065-PCO-EI addressed the same issue. That Order recognizes that section 120.80(13), F.S. exempts cost recovery clause matters from rule making.

OPC: No. The Commission lacks the express statutory authority to do rulemaking. Further, even if the Commission has jurisdiction, FPL may state there is an exception to rulemaking for recovery of costs through the Fuel Clause. See Section 120.80(13)(a), F.S. First, the Commission, not FPL, must assert this exemption from rulemaking. Second, there is nothing in the exemption from rulemaking that prohibits the Commission from establishing a rule to provide guidelines for gas reserves investments that will change customer rates. Third, notwithstanding this exemption from rulemaking, Section 366.06(1), F.S., specifically mandates that all applications for changes in rates shall be made under the rules and regulations as prescribed by the Commission.[14] This specific mandate controls over Section 120.80(13)(a), F.S., general exemption from rulemaking for clause proceedings.[15] Requesting approval for the Guidelines is de facto a pre-application for changes in customer rates on an automatic, going-forward basis for gas projects that meet the Guidelines. Therefore, any Guidelines approved for FPL and established without rules violate the mandate of Section 366.06(1), F.S. Since there is no express authority to allow investor owned monopoly electric utilities to recover costs associated with obtaining natural gas at the "wellhead" from gas reserves investments, FPL's proposal cannot get past first base (statutory authorization) let alone second base (rulemaking). As the Regulator, the Commission should state that FPL's has struck-out with its overreaching proposal.

FIPUG: Yes. Florida Statutes provides that statements of policy should be adopted through rulemaking. Rulemaking affords affected parties notice and the opportunity to participate in the development of any oil and gas exploration and production policy that would be applied prospectively. Such wide-ranging policy pronouncements should be put in place through

[14] . . . All applications for changes in rates shall be made to the commission in writing under rules and regulations prescribed, and the commission shall have the authority to determine and fix fair, just, and reasonable rates that may be requested, demanded, charged, or collected by any public utility for its service. . . . Section 366.06(1), F.S.

[15] Commission legal and technical staff have recognized the need for a rule when a utility applies for a change in rates, even in the Fuel Clause. See Case Background recommending approval of Rule 25-6.0424, F.A.C., Petition for Mid-Course Correction, in Docket No. 100084-EI. (http://www.psc.state.fl.us/library/FILINGS/10/03779-10/03779-10.pdf) The "Purpose and Effect" of this rule clearly recognizes that the ". . . specific language of Sec. 366.06(1), F.S., [] requires that all applications for changes in rates shall be made to the Commission in writing under prescribed rules and regulations. . . ." See Order No. PSC-10-0332-NOR-EI, issued May 25, 2010 at 2.

rulemaking. FPL's "guidelines" are tantamount to proposed rules and should be considered in an appropriately noticed proceeding in accord with chapter 120, Florida Statutes.

Staff Analysis: This analysis addresses whether adoption of FPL's proposed Guidelines are applicable to all other IOUs and, if so, whether the Commission is required to engage in rulemaking to adopt the guidelines.

In its petition FPL proposed a detailed set of guidelines FPL asserts are designed to establish a framework whereby FPL can participate in future gas reserve projects and recover its costs through the fuel clause without prior Commission approval. (FPL BR 1) FPL takes the position that no rules are required to adopt its guidelines. (FPL BR 23) In support, FPL cites Order No. PSC-14-0665-PCO-EI, denying FIPUG's motion to strike FPL's request to establish guidelines related to oil and gas based on a finding by the Prehearing Officer that cost recovery clauses are specifically exempt from rulemaking under Section 120.80(13)(a), F.S. [16] (FPL BR 23)

OPC admits that the Commission is exempt from "some aspect of rulemaking" but that certain Commission orders, such as the order setting hedging guidelines[17] are "de facto or surrogate rules."[18] (OPC BR 39) OPC argues that the provisions of Section 366.06(1), F.S., providing that all applications for changes in rates shall be made under the rules and regulations as prescribed by the Commission, controls over the exemption in Section 120.80(13)(a), F.S. (OPC BR 40) In support, OPC cites language from a staff recommendation in a proceeding involving the promulgation of Rule 25-6.0424, F.A.C., setting requirements for filing a petition for mid-course correction, in Docket No. 100084-EI. [19] (OPC BR 39) A petition for mid-course correction seeks a change to fuel factors and is typically filed in fuel clause proceedings. OPC contends that requesting approval for the guidelines is de facto a pre-application for changes in customer rates on an automatic, going-forward basis for gas projects that meet the guidelines. Therefore, OPC argues, the Commission violates the mandate of Section 366.06(1), F.S., if it adopts the FPL guidelines without promulgating rules. (OPC BR 39-40)

FIPUG takes the position that the Commission should engage in rulemaking, because FPL's guidelines are tantamount to proposed rules and should only be considered in an appropriately noticed proceeding in accord with Chapter 120, F.S. (FIPUG BR 3, 6) FIPUG argues that rulemaking affords affected parties notice and the opportunity to participate in the development of a prospective application of a policy regarding the issues raised by FPL's petition to adopt guidelines for future oil and gas exploration and production ventures. (FIPUG BR 6) FIPUG recommends that the Commission pursue rulemaking either directly or through

[16] See Order No. PSC-14-0665-PCO-EI, issued on November 17, 2014, in Docket No. 140001-EI, In re: Fuel and purchased power cost recovery clause with generating performance incentive factor.
[17] See 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 incentive factor.
[18] The term "de facto" or "surrogate rule" is not found in any provision of Chapter 120, F.S.
[19] Document No. 03779-10, filed May 6, 2010, Revised Recommendation for May 13, 2010 Agenda. Staff notes that language in a staff recommendation does not constitute Commission action. Order No. PSC-10-0332-NOR-EI, issued May 25, 2010, in Docket No. 100084, In re: Initiation of rulemaking to adopt Rule 25-6.0424, F.A.C., Petition for Mid-Course Correction, does not address this portion of the staff's recommendation.

incipient policy on a case-by-case approach. (FIPUG BR 4) FIPUG also argues that such wide-ranging policy pronouncements should be put in place through legislative enactment. (FIPUG BR 2) FIPUG further states that the adoption of FPL's guidelines will establish precedent for other utilities to request approval of projects similar to FPL's gas reserves project. (FIPUG BR 2)

The first question is whether FPL's proposed Guidelines, if adopted, are rules. Section 120.52(7), F.S., defines a rule as an agency statement of general applicability that implements, interprets, or prescribes law or policy, or describes the procedure or practice requirements of an agency and includes any form which imposes any requirement or solicits any information not specifically required by statute or by an existing rule.

When deciding whether a challenged action constitutes a rule, a court analyzes the action's general applicability, requirement of compliance, or direct and consistent effect of law. Fla. Dep't of Fin. Servs. v. Capital Collateral Reg'l Counsel-Middle Region, 969 So. 2d 527, 530 (Fla. 1st DCA 2007). The analysis is predicated on whether the action has a direct effect on the other regulated utilities, adversely affects any substantive right, constitutes a denial or withdrawal of a right, imposes any new or additional requirements, or has the direct and consistent effect of law. Volusia County Sch. Bd. v. Volusia Home Builders Ass'n, Inc., 946 So. 2d 1084, 1089 (Fla. 5th DCA 2006).

In Florida Public Service Com. v. Central Corp., 551 So. 2d 568, 569 (Fla. 1st DCA 1989), the court held that a Commission interim rate order imposing a temporary "hold subject to refund" requirement was an invalid unpromulgated rule because the order specifically stated that the requirement applied to all alternate service providers furnishing operator-assisted long distance telecommunications services, not just Central Corporation. The court determined that the order was a rule as it imposed an immediate requirement not otherwise required by statute or existing rule because the providers either had to change previously approved rates to match those charged by local exchange companies, or set monies aside to cover the potential refund obligation.

Unlike the Commission order at issue in Central Corp. or the order establishing the hedging guidelines,[20] the FPL proposed Guidelines, if adopted, affect only FPL. The guidelines neither have a direct effect on the other electric utilities that are parties in the fuel clause proceedings, adversely affect any of their substantive rights, impose any new or additional requirements, nor have the direct and consistent effect of law. Thus, the guidelines are not a statement of general applicability and do not rise to the level of a rule under the provisions of Section 120.52(7), F.S.

In 1991, the Florida Legislature enacted Section 120.54(1)(a), F.S., which provides that rulemaking is not a matter of agency discretion and requires each agency statement defined as a rule by Section 120.52 to be adopted by the rulemaking procedure provided in Chapter 120, F.S. as soon as feasible and practicable. See: Department of Highway Safety and Motor Vehicles v.

[20] See 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 incentive factor.

Schluter, 705 So. 2d 81 (Fla. 1st DCA 1997). However, Section 120.80(13)(a), F.S., specifically exempts the Commission from the mandatory rulemaking requirements of Section 120.54(1)(a), F.S. The exemption applies to any Commission statements that relate to cost-recovery clauses, factors, or mechanisms implemented pursuant to Chapter 366, F.S., relating to public utilities. The Commission has, in the past, established guidelines and procedures for fuel clause proceedings that have general applicability through Commission orders without promulgating rules.[21] The Commission specifically addressed the Section 120.80(13)(a), F.S., exemption in Order No. PSC-99-1741-PAA-EI when it ruled that, despite containing agency statements of widespread applicability, an order issued as part of the fuel and purchased power cost recovery clause is exempt from the rulemaking requirements of Chapter 120, F.S. [22]

OPC's argument that Section 120.80(13)(a), F.S., does not control because the petition for approval of the guidelines "is de facto a pre-application for changes in customer rates" under Section 366.01, F.S., is inapposite to the issue at hand and misapprehends the statutory interpretation of the relevant statutory sections.[23] Rule 25-6.0424, F.A.C., setting requirements for petitions for mid-course correction involves petitions for change in rates. The petition to adopt guidelines is clearly not an application for a change in rates. Adopting OPC's argument, the Commission would be required to promulgate rules to implement *all* Commission orders setting procedures, factors or mechanisms in cost-recovery clauses and renders the provisions of Section 120.80(13)(a), F.S., meaningless. A basic rule of statutory construction is that the Legislature does not intend to enact useless provisions, and courts avoid readings that would render part of a statute meaningless. American Home Assurance Co. v. Plaza Materials Corp., 908 So. 2d 360, 366 (Fla. 2005); Kasischke v. State, 991 So. 2d 803, 808 (Fla. 2008) (holding that a court must avoid interpreting a statute so as to render the statute meaningless).

In conclusion, if the Commission adopts guidelines, it is not required to engage in rulemaking. First, the guidelines are not rules under the definition in Section 120.52(7), F.S. Second, the Commission is exempt from rulemaking under the provisions of Section 120.80(13)(a), F.S., applicable to cost-recovery clauses, factors, or mechanisms.

[21] See 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 incentive factor.
[22] See Order No. PSC-99-1741-PAA-EI, issued September 3, 1999, in Docket No. 990771-EI, In re: Petition by Florida Power Corporation for approval of regulatory treatment associated with the sale of replacement capacity and energy to the City of Tallahassee.
[23] Section 366.06(1), F.S. does not address "pre-applications" for a change in rates.

Issue 9: Should this docket be closed?

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

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

FPL GAS RESERVES GUIDELINES[24]

Florida Power and Light Company's ("FPL" or "the Company") goals in purchasing natural gas to supply its power plants are reliability, price stability and low cost. Participating in gas reserve projects through a joint development agreement is a form of long-term hedging that can be a valuable supplement to FPL's existing short-term hedging program.

The Florida Public Service Commission ("Commission") previously has found "that the purpose of hedging is to reduce the impact of volatility in the fuel adjustment charges paid by an IOU's customers, in the face of price volatility for the fuels (and fuel price-indexed purchased power energy costs) that the IOU must pay in order to provide electric service." Further, the Commission found the primary purpose of hedging is to "reduce the variability or volatility in fuel costs paid by customers over time." *(Order No. PSC-08-0667-PAA-EI, Attachment A, page 2)*

Because of the natural depletion rate of shale-based gas production, it is understood that FPL will need to continue pursuing new gas reserve project opportunities to compensate for declining production from existing projects, as well as to expand the percentage of FPL's gas requirements that are hedged long-term. Moreover, it is clear that market participants and potential counterparties expect and value the ability to respond to opportunities quickly. Accordingly, a successful market strategy requires an established framework within which FPL may negotiate and consummate transactions.

I. SCOPE OF GAS RESERVE PROJECT PARTICIPATION

- Gas reserve projects will help reduce the overall portfolio price volatility and supply risk. The transactions will lessen the impact to customers if gas prices spike or rise and stay high for an extended period of time. Even though each transaction individually will represent a very small percentage of the Company's supply portfolio, collectively these transactions would help dampen the effects of price volatility.
- Guideline I.A: Overall, the estimated aggregate output of all gas reserve projects will not exceed the following percentages of FPL's projected average daily natural gas burn:

Year	Maximum Volume as a Percentage of Average Daily Burn
2015	~~15%~~ 5%
2016	~~20%~~ 7.5%
2017	~~25%~~ 10%

[24] As discussed in Issue 5, staff is recommending the Commission not approve FPL's proposed Gas Reserves Guidelines. However, if the Commission finds it is appropriate to establish guidelines at this time, staff recommends the modifications reflected in the type-and-strike format presented in Attachment A.

- Guideline I.B: FPL will provide an annual update ~~to the three year window presented in Guideline I.A~~ informing the Commission of the relative percentage of average daily burn the aggregate output of all gas reserve projects represent as part of its Risk Management Plan filed in early August each year with the Estimated/Actual Testimony filing. The maximum volume as a percentage of average daily burn will be capped at 10 percent until such time the Commission considers this Guideline in a future proceeding.
- Guideline I.C: Because gas reserve transactions provide a hedging benefit for FPL and its customers, the estimated aggregate volumes of natural gas from all gas reserve transactions in each calendar year will be netted against the amounts that FPL forecasts to hedge pursuant to FPL's annual Risk Management Plan. FPL will hedge the net amount as prescribed in the Risk Management Plan.
- Guideline 1.D: FPL will not obligate itself to invest more than ~~$750~~ $250 MM in the aggregate on gas reserve projects over the course of any one calendar year.

II. CUSTOMER SAVINGS

To ensure transparency and to demonstrate that FPL's customers are receiving the greatest opportunity for fuel savings associated with investments in gas reserve projects, FPL will provide an annual detailed comparison of all gas reserve projects entered into on behalf of FPL, USG, and/or any other affiliate or subsidiary of NextEra Energy as part of its Risk Management Plan filed in early August each year with the Estimated/Actual Testimony filing. This annual filing will provide the same information for each gas reserve project entered into by any affiliate or subsidiary of NextEra Energy that was used to support or justify the appropriateness of each gas reserve project entered into by FPL during the reporting period. In particular, this filing will show all material assumptions relied upon to support each gas reserve project including the capital investment amount, will calculate the associated revenue requirement for each gas reserve project, and will provide the net present value savings for each gas reserve project entered into by any affiliate or subsidiary of NextEra Energy.

- Investment in gas reserve projects can offer significant price stability for the volumes produced, while also providing customer savings in a market of rising gas prices. A benefit of a well-managed gas reserves investment program is secure low-cost natural gas for our customers for years into the future that delivers an expected pricing discount relative to the forward curve. Since typical wells produce for 40 to 60 years, gas production joint ventures can provide stable pricing for decades to come, thus helping to achieve the Commission's stated goal for hedging to reduce price volatility for customers.
- Transactions of this type can result in lost opportunities for savings in the fuel costs to be paid by customers if fuel prices actually settle at lower levels than at the time the gas reserves investments were made. However, since only a portion of FPL's fuel requirements is procured through gas reserves investments, FPL maintains the ability to purchase low priced fuel when the opportunity arises. Moreover, in some projects it may be possible to delay the drilling plan and/or reduce the production

volume from existing wells in the event of unexpected price declines. Conversely, when fuel prices settle at higher levels than at the time the gas reserves investments were made, increased customer savings are a direct result of the gas production joint venture.

- Guideline II.A: Evaluation of the prudence of FPL's having entered into a new gas reserve project will be based on a showing that the project is estimated to generate savings for customers on a net present value basis, relying solely on information relative to these Guidelines available to FPL at the time the transaction was entered, as well as any information FPL should have known at the time, including the use of an independent third party reserve engineering report and FPL's standard fuel price forecasting methodology. As part of the annual filing to the Risk Management Plan discussed above, FPL will provide the same showing of results (gains or losses) for every gas reserve project entered and/or held by any affiliate or subsidiary of NextEra Energy. The results for all gas reserve projects will be evaluated using the same forecast of natural gas prices used to project customer fuel savings for FPL gas reserve projects.

  For any gas reserve projects secured pursuant to these guidelines, FPL will use an independent third party auditor in performing the audits of the associated transactions. FPL will work with Commission staff to develop the scope of these audits. In addition, FPL will use the necessary subaccounts, under the FERC system of accounting, which will correspond on a one-on-one basis with the oil and gas system of accounts used by the Gas Reserve Company set up to record FPL's investments in gas reserve projects.

III. SUPPLY DIVERSITY

- Gas reserve projects will provide beneficial geographic diversity of fuel supply. Catastrophic events, such as hurricanes, affect FPL's ability to procure and deliver fuel. Investments in multiple gas reserves across various regions will reduce the impact of a single event disrupting FPL's entire fuel supply.
- Gas reserve projects also will increase the diversity of FPL's supply from a physical perspective, as well as a financial one. The longer time frame of these investments offers diversity when compared to the current financial and physical contract lengths in the existing hedging program.
- FPL intends over time to transact with a wide range of suppliers so as to minimize concentration of supply with any one producer. This will allow FPL to transact in multiple regions and will also provide for reduced credit exposure to any one entity. To minimize counterparty risk, FPL will only transact with producers that are also producers for existing gas reserve projects held by one or more NextEra Energy affiliates or subsidiaries.
- Guideline III.A: FPL will only enter into transactions for onshore gas reserve projects, located in areas with reserves that have a well-established history of gas production. Florida does not meet these criteria. In addition, FPL will only enter into transactions for gas reserve projects that involve wells classified as "Proved Reserves" or "Probable Reserves" as defined by the Securities and Exchange

Commission for public company reporting. Because one of the primary purposes of gas reserve projects is a physical source of supply to serve its natural gas needs, at least 50 percent of the wells in each gas reserve project must be classified as "Proved Reserves." FPL will not enter into transactions for gas reserve projects that involve wells classified as "Possible Reserves."

- Guideline III.B: Because one of the primary purposes of gas reserve projects is a physical source of supply to serve its substantial gas needs, FPL will only enter into a transaction if there is a transportation path available to deliver the gas produced from that project to FPL's service territory. Texas, Louisiana, Oklahoma, Arkansas, Mississippi, Alabama, West Virginia, Ohio, and Pennsylvania currently meet this criterion. FPL will make use of its transportation portfolio, along with considering new physical paths. The costs of any new transportation needed to deliver gas from a gas reserve project will be taken into consideration when analyzing the economics of that project.

IV. CHARACTERISTICS OF GAS RESERVES

- Natural gas production consists of a combination of hydrocarbons, which can include methane, natural gas liquids ("NGLs"), and oil. The composition of natural gas production varies region by region and within individual regions.
- FPL's natural gas plants burn primarily methane and can accommodate only a very small percentage of other hydrocarbons. However, there are active third party markets for purchase and sale of NGLs and oil.
- There are a range of designations for reserves denoting the degree of certainty that the predicted quantity of gas is commercially recoverable from the well under current conditions: Proved, Probable, and Possible. FPL's gas reserve portfolio would appropriately be comprised of a wide range of projects, including reserves that fall within each of those categories.
- Guideline IV.A: Although there is significant customer value in the production and sale of NGLs and oil, the purpose of FPL's gas reserves program is to provide a source of physical supply of natural gas to serve its power plants. For that reason, FPL will only enter into a transaction for a gas reserve project if the estimated output of the wells in the project contains at least 50% from methane by volume.
- Guideline IV.B: All NGLs and oil produced from a gas reserve project will be sold at market prices and the resulting revenues will be credited to the Fuel Clause to offset the production costs for which customers are responsible, thus lowering the effective cost of natural gas. The projected revenues from NGLs and oil produced from a gas reserve project will be taken into consideration when analyzing the economics of that project.

Flexibility to respond to market opportunities is in the best interest of FPL and its customers. Therefore, it is understood that FPL may (i) propose modifications to these guidelines in the annual update provided pursuant to Guideline I.B above, and (ii) seek Fuel Clause recovery for a project that deviates from one or more of the guidelines upon a showing that the project nonetheless is expected to benefit FPL

customers. In order to provide due process to all parties, any proposed modifications to these guidelines filed in August will be the subject of the hearing in the following year's Fuel Clause proceeding. To be considered in the current year's Fuel Clause hearing, any proposed modifications to the guidelines must be filed by March 1. Eligibility for Fuel Clause recovery of any gas reserve project that deviates from one or more of the guidelines will be considered on a case-by-case basis. Such projects must be filed with the Commission by March 1 to be considered in that year's Fuel Clause proceeding.

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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (Vogel, T. Brown, Cicchetti, Mouring)
Division of Economics (Hudson, Thompson)
Division of Engineering (King, Watts)
Office of the General Counsel (Tan)

RE: Docket No. 140147-WS – Application for staff-assisted rate case in Sumter County by Jumper Creek Utility Company.

AGENDA: 06/18/15 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate (Except for Issues 11, 13 and 14)

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Edgar

CRITICAL DATES: 01/05/16 (15-Month Effective Date (SARC))

SPECIAL INSTRUCTIONS: None

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Case Background

Jumper Creek Utility Company (Jumper Creek or Utility) is a Class C water and wastewater utility serving approximately 43 customers in Sumter County. Jumper Creek's service territory is located in the Southwest Florida Water Management District (SWFWMD) and is not in a water use caution area. The Utility's application in the instant docket shows total gross revenues of $13,078 for water and $18,624 for wastewater, with net operating losses of $10,424 and $423 for water and wastewater, respectively.

The Jumper Creek systems were originally owned by Jumper Creek Manor Homeowners' Association, Inc. (HOA). The HOA, as a nonprofit entity, was exempt from Commission regulation, pursuant to Section 367.022(7), Florida Statutes (F.S.). In a 2010 transfer docket, by Order No. PSC-11-0377-PAA-WS, the Jumper Creek systems were transferred to Aqua Utilities Florida, Inc. (AUF).[1] The existing rates at the time of this transfer remained the same. AUF subsequently transferred the systems to Jumper Creek Utility Company in a 2013 transfer docket by Order No. PSC-14-0299-PAA-WS,[2] where Jumper Creek's net book value was last established. The instant case will be the first time the Commission will establish rates for the systems.

Jumper Creek filed its application for a Staff-Assisted Rate Case (SARC) on August 1, 2014, and subsequently completed the Commission's filing requirements. October 3, 2014 was established as the official filing date in this case.

The Commission has jurisdiction in this case pursuant to Sections 367.011, 367.0814, 367.101, and 367.121, F.S.

[1]Issued September 12, 2011 in Docket No. 100114-WS, In re: Application for approval of transfer of Horizon Homes of Central Florida, Inc. and Five Land Group, LLC's water and wastewater systems to Aqua Utilities Florida, Inc., and for amendment of Certificate Nos. 507-W and 441-S, in Sumter County.

[2]Issued June 11, 2014 in Docket No. 130176-WS, In re: Application for approval of transfer of certain water and wastewater facilities and Certificate Nos. 507-W and 441-S of Aqua Utilities Florida, Inc. to Jumper Creek Utility Company in Sumter County.

Discussion of Issues

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

Recommendation: Yes. Staff recommends that the condition of the water and wastewater treatment facilities are satisfactory and the water provided by Jumper Creek is meeting applicable water quality standards, including primary and secondary standards, as prescribed in the Florida Department of Environmental Protection's (DEP) rules. It also appears that the Utility has attempted to address the customers' concerns. Therefore, staff recommends that the overall quality of service for the Jumper Creek water and wastewater systems in Sumter County is 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. 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 operational conditions of the Utility's plant and facilities, and the Utility's attempt to address customer satisfaction. Jumper Creek's compliance with DEP and the SWFWMD regulations; and customer comments or complaints received by the Commission are also reviewed.

Quality of Utility's Product and Operating Condition of the Utility's Plant and Facilities

Jumper Creek's service area is located near Bushnell, Florida, in Sumter County. The raw water source is ground water, which is obtained from two wells in the service area and is treated. The water treatment processing sequence is to pump raw water from the aquifer, inject calcium hypochlorite, and distribute.

In addition to primary contaminants, Section 367.0812, F.S., requires the Commission to consider secondary contaminants as part of the overall quality of service. Secondary contaminants are those contaminants a customer would likely notice because they impact things like color or smell. However, secondary contaminants are not a health risk and DEP does not typically undertake enforcement actions for secondary standards, unless another type of contaminant exceeds the maximum contaminant levels (MCL).

Jumper Creek is current in all of its required chemical analyses. Staff reviewed the chemical analysis with samples dated August 20, 2014, for the disinfection byproducts and January 24, 2012, for all other contaminants. Laboratory tests show that Jumper Creek's finished water product is well below the MCLs allowed by DEP for all primary and secondary contaminants, and there appear to be no water quality compliance issues with this facility.

Staff also reviewed the Utility's last two DEP Sanitary Survey Reports, dated March 18, 2010, and May 14, 2013. For each inspection, no deficiencies were found and DEP determined that the facility was in compliance with its rules and regulations. Based on Jumper Creek's DEP compliance, staff recommends that the operational condition of the water treatment plant (WTP) is satisfactory.

The wastewater treatment plant (WWTP) is an extended aeration facility with reclaimed water directed to a rapid infiltration basin. Staff reviewed the last Compliance Evaluation Inspection (CEI) performed by DEP, dated April 17, 2014. DEP's report listed four deficiencies. First, one of the three blowers did not work. Jumper Creek corrected this deficiency by installing a new blower motor in December 2014. Second, the automatic timer for the blowers did not work. The Utility replaced the automatic timer in April 2014. Third, the lift station wet well needed cleaning. The Utility cleaned the wet well and notified DEP in May 2014. Fourth, DEP stated there was no current flow meter calibration onsite due to the elapsed time meter not functioning. Jumper Creek repaired and calibrated the meter, and reported its actions to DEP in May 2014.

During its April 14, 2015 site inspection, staff verified that all of the deficiencies noted on DEP's CEI had been corrected. However, staff observed that another blower motor was not working. The Utility replaced the motor and submitted an invoice for the replacement to be included in the instant docket. Based on Jumper Creek's status with DEP and its prompt repair actions, staff recommends that the operational condition of the WWTP is satisfactory.

The Utility's Attempt to Address Customer Satisfaction

A customer meeting was held in Webster, Florida, on April 1, 2015. Four of the Utility's customers attended the meeting and three spoke. Prior to the customer meeting, on November 12, 2014, one customer sent written comments to the Commission objecting to the rate increase. No other customers have submitted written comments to the Commission.

All of the customers who spoke were concerned about the rate increase. In addition to rates, one customer had the following concerns: (1) high levels of chlorine in the water; and (2) odor from the WWTP.

Subsequent to the customer meeting, Jumper Creek tested the chlorine residual at customers' homes, and reported the results to the Commission in a letter dated April 7, 2015. DEP requires water suppliers to maintain a minimum free chlorine residual of at least 0.2 milligrams per liter (mg/L), or a minimum combined chlorine residual of 0.6 mg/L throughout the system at all times. DEP also has designated a maximum system chlorine level of 4.0 mg/L. Jumper Creek reported that all of the customers' chlorine residuals tested at 1.0 mg/L, above the minimum level required, but well below the maximum allowed.

Regarding the odor from the WWTP, after the customer meeting the Utility spoke with the customer who voiced the concern. The WWTP is located behind some homes that are across the street from this customer. After speaking with the customer, the Utility found that there was a sewer clean out which did not have a proper cap on it protruding from the ground near the customer's home. Jumper Creek replaced the cap on April 6, 2015. The Utility reported that, on subsequent site visits, no odor was detected.

Staff reviewed the complaints in the Commission's Complaint Tracking System for the Jumper Creek water and wastewater systems from January 1, 2009, through December 31, 2013. Staff did not find any complaints filed by customers served by Jumper Creek's WTP or WWTP.

On January 15, 2015, staff sent a letter to DEP requesting information on complaints that were filed with DEP regarding this water system from January 1, 2009, through December 31, 2013. DEP reported that it received no complaints regarding the Jumper Creek WTP during that time. Jumper Creek stated that no complaints have been filed with the Utility since it began operations as Jumper Creek Utility Company.

Summary

Staff recommends that the condition of the water and wastewater treatment facilities are satisfactory and the water provided by Jumper Creek is meeting applicable water quality standards, including primary and secondary standards, as prescribed in the DEP rules. It also appears that the Utility has attempted to address the customers' concerns. Therefore, staff recommends that the overall quality of service for the Jumper Creek water and wastewater systems in Sumter County is satisfactory.

Issue 2: What are the used and useful (U&U) percentages of Jumper Creek's WTP, WWTP, and distribution and collection systems?

Recommendation: Jumper Creek's WTP should be considered 90.6 percent U&U, its WWTP should be considered 7.8 percent U&U, and its distribution and collection systems should each be considered 100 percent U&U. There is no indication of excessive unaccounted for water (EUW) or excessive inflow and infiltration (I&I). (Watts)

Staff Analysis: Jumper Creek's water system has a 12-inch well rated at 600 gallons per minute (gpm) and an 8-inch well rated at 570 gpm, for a total capacity of 1,170 gpm. The Utility has a 13,000-gallon hydropneumatic tank for system pressurization. A hypochlorination system is used for disinfection and water from the tank is pumped into the water distribution system.

The distribution system is a network of approximately 5,410 linear feet of 6-inch PVC pipe. According to the Utility, there are 9 fire hydrants in its service area.

The WWTP is a 35,000 gallon per day (gpd) extended aeration facility operated to provide secondary treatment with basic disinfection. Reclaimed water is directed to a two-cell rapid infiltration basin with a 12,100 square foot wetted area.

The collection system is a network of force mains, collecting mains, and a lift station. According to the Utility's records, the force mains consist of approximately 1,088 linear feet of 4-inch PVC pipe, and the collecting mains consist of approximately 4,872 linear feet of 8-inch PVC pipe. According to the Utility, there are 23 manholes.

Excessive Unaccounted for Water

Rule 25-30.4325, F.A.C., describes EUW as unaccounted for water in excess of 10 percent of the amount produced. Unaccounted for water is all water that is produced and not sold, metered, or accounted for in the records of the Utility. Rule 25-30.4325(10), F.A.C., provides that to determine whether adjustments to plant and operating expenses, such as purchased electrical power and chemicals cost, 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 purposes, such as flushing, and the gallons sold to customers from the total gallons pumped for the test year.

The Utility's records indicated 2,484,730 gallons of water were produced during the test year, 2,260,000 gallons of water were sold to customers, and 112,462 gallons were used for other purposes. Thus, unaccounted for water is 4.5 percent of the amount produced, resulting in no excessive unaccounted for water.

Water Treatment Plant Used &Useful

Pursuant to Rule 25-30.4325, F.A.C., the U&U percentage of a WTP without storage is calculated by dividing the peak system demand by the firm reliable capacity (FRC). The system demand is based on the single maximum day in the test year less EUW, plus a fire flow allowance and a growth allowance.

Because the Utility has no storage capacity, the FRC is based on the capacity of the system excluding the largest well, expressed in gpm. The Utility has two wells, rated at 600 gpm and 570 gpm. Thus, excluding the larger well and using the capacity of the remaining well, the Utility's FRC is 570 gpm.

The peak day of 23,600 gallons (or 16.4 gpm), which occurred on March 31, 2014, appears to be appropriate since it is not associated with unusual occurrences. Fire flow for the Utility's service area is 500 gpm. As discussed above, the Utility's EUW is zero. Pursuant to Rule 25-30.431, F.A.C., a linear regression analysis of the Utility's historical growth shows that there has been no growth for the 5-year statutory growth period. Thus, a growth allowance is not considered. Therefore, pursuant to Rule 25-30.4325, F.A.C., staff recommends that the WTP be considered 90.6 percent U&U. [(16.4gpm+500gpm)/570gpm]

Inflow & Infiltration

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 water sold 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. The Utility's records indicated that it treated less wastewater (931,600 gallons) than it would be allowed for infiltration and inflow as described above (1,072,488 gallons). Thus, the Utility had no excessive I&I for the test year.

Wastewater Treatment Plant Used &Useful

Pursuant to Rule 25-30.432, F.A.C., the U&U analysis of the Utility's WWTP is based on the customer demand compared with the permitted plant capacity, with customer demand measured on the same basis as permitted capacity. The DEP permitted capacity for this facility is 35,000 gpd based on a three-month rolling average daily flow. Based on the comparable flow of 2,728 gpd during the test year, with no consideration given for growth or excessive I&I, staff recommends that the WWTP be considered 7.8 percent U&U.

Water Distribution and Wastewater Collection Systems Used &Useful

The U&U analysis for the water distribution and wastewater collection systems are determined by dividing the number of lots connected to the systems by the number of lots fronting mains in the service area. Consideration is given for growth, if applicable. The Utility reported 43 connections during the test year, with 115 lots fronting mains. Staff has calculated the water distribution and wastewater collection systems to be 37.4 percent U&U. In Order No. PSC-11-0377-PAA-WS, it was determined that the Utility's distribution and collection systems were developer contributed and imputed in contributions in aid of construction. Therefore, staff recommends that the water distribution and wastewater collection systems be considered 100 percent U&U.[3]

Summary

Staff recommends that Jumper Creek's WTP should be considered 90.6 percent U&U, its WWTP should be considered 7.8 percent U&U, and its distribution and collection systems should each be considered 100 percent U&U. There is no indication of EUW or excessive I&I.

[3]Order No. PSC-11-0377-PAA-WS, issued September 12, 2011, in Docket No. 100114-WS, In re: Application for approval of transfer of Horizon Homes of Central Florida, Inc. and Five Land Group, LLC's water and wastewater systems to Aqua Utilities Florida, Inc., and for amendment of Certificate Nos. 507-W and 441-S, in Sumter County.

Issue 3: What is the appropriate average test year water rate base and wastewater rate base for Jumper Creek?

Recommendation: The appropriate average test year water rate base for Jumper Creek is $53,253 and the average test year wastewater rate base is a negative $12,038. (Vogel)

Staff Analysis: Jumper Creek's net book value was last established in its 2013 transfer docket by Order No. PSC-14-0299-PAA-WS.[4] The test year ended June 30, 2014, was used for the instant case. A summary of each water rate base and wastewater rate base component, and recommended adjustments, are discussed below.

Utility Plant in Service (UPIS): The Utility recorded UPIS of $511,881 for water and $389,284 for wastewater. The Jumper Creek staff audit noted no exceptions to the Utility's UPIS balances. Staff has included three pro forma additions to wastewater plant totaling $3,860 along with retirements of $2,895 for these items. The Utility included a fourth pro forma item for its water plant in service that staff has determined should be covered in the Utility's contract with U.S. Water Services Corp. (USWSC). Staff therefore has not included this pro forma item. Staff has increased wastewater plant in service by $965. Staff recommends that the appropriate UPIS balances are $511,881 for water and $390,249 for wastewater.

Land & Land Rights: The Utility recorded a test year land value of $2,272 for water and $18,722 for wastewater. No adjustments are necessary; therefore, staff recommends that the appropriate land balances are $2,272 and $18,722 for water and wastewater, respectively.

Non-Used and Useful (non-U&U) Plant: The Utility recorded non-U&U plant balances of $0 for water and $128,851 for wastewater. As discussed in Issue 2, the WTP should be considered 90.6 percent U&U and the WWTP should be considered 7.8 percent U&U. In Issue 2, Jumper Creek's distribution and collection systems were calculated as 37.4 percent U&U. In Order No. PSC-11-0377-PAA-WS, it was determined that the Utility's distribution and collection systems were developer contributed and imputed in contributions in aid of construction, therefore, the distribution and collection systems should be considered 100 percent U&U.[5]

Application of the U&U percentages to the average plant balances, associated average accumulated depreciation balances, and associated average acquisition adjustment (AA) balances results in a net increase of $9,095 for water and a net decrease of $81,606 for wastewater non-U&U components, respectively. Therefore, staff's recommended non-U&U plant balances are $9,095 for water and $47,245 for wastewater.

Contributions In Aid of Construction (CIAC): The Utility recorded CIAC balances of $157,236 for water and $221,828 for wastewater. No additions occurred in the test year, and staff determined that no adjustments are necessary. Staff's recommended CIAC is $157,236 and $221,828 for water and wastewater, respectively.

[4]Order No. PSC-14-0299-PAA-WS, issued June 11, 2014, in Docket No. 130176-WS, In re: Application for approval of transfer of certain water and wastewater facilities and Certificate Nos. 507-W and 441-S of Aqua Utilities Florida, Inc. to Jumper Creek Utility Company in Sumter County.
[5]Issued in Docket No. 100114-WS.

Accumulated Depreciation: Jumper Creek recorded a test year accumulated depreciation balance of $151,215 for water and $126,053 for wastewater. 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, and as a result has decreased wastewater accumulated depreciation by $2,830. Staff has decreased accumulated depreciation by $11,885 for water and $8,097 for wastewater to reflect the simple average. Staff's total adjustments to this account are a decrease of $11,885 for water and $10,927 for wastewater. Staff's adjustments result in accumulated depreciation balances of $139,330 for water and $115,126 for wastewater.

Accumulated Amortization of CIAC: The Utility recorded amortization of CIAC of $38,790 for water and $54,724 for wastewater. Amortization of CIAC has been recalculated by staff using composite depreciation rates, and as a result staff has decreased water accumulated amortization of CIAC by $6,430 and increased wastewater accumulated amortization of CIAC by $3,531. Also, staff has decreased water accumulated amortization of CIAC by $2,195 and wastewater accumulated amortization of CIAC $4,078 to reflect the simple average. Staff's net adjustments result in a decrease of $8,625 for water and $547 for wastewater. Staff's recommended accumulated amortization of CIAC balances are $30,166 for water and $54,177 for wastewater.

Acquisition Adjustment (AA): The Utility recorded AA balances of $208,895 for water and $104,855 for wastewater. Due to the timing of when the acquisition adjustment occurred within the test year, an averaging adjustment would not be appropriate. Thus, staff did not adjust the balance. Therefore, staff recommends that the appropriate acquisition adjustment balances are $208,895 for water and $104,855 for wastewater.

Accumulated Amortization of the AA: The Utility recorded an accumulated amortization of the AA balance of $0 for water and $0 for wastewater. Staff has increased these accounts by $1,125 for water and $572 for wastewater to reflect the appropriate amount of accumulated amortization of the AA. Staff increased these balances by $20,143 for water and by $10,249 for wastewater to include a full year of accumulated amortization of the AA. Inclusion of a full year of amortization more appropriately represents the effect of the AA on a going-forward basis. Staff's total adjustments to this account result in accumulated amortization of the AA balances of $21,268 for water and $10,821 for wastewater.

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 $2,222 for water (based on O&M expense of $17,778/8), and $3,047 for wastewater (based on O&M expense of $24,377/8).

Rate Base Summary: Based on the foregoing, staff recommends that the appropriate average test year rate base for water is $53,253 and the average test year rate base for wastewater is a negative $12,038. Water and wastewater rate bases are shown on Schedule Nos. 1-A and 1-B, respectively. The related adjustments are shown on Schedule No. 1-C.

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

Recommendation: The appropriate return on equity (ROE) is 8.74 percent with a range of 7.74 percent to 9.74 percent. The appropriate overall rate of return is 8.62 percent. (Vogel)

Staff Analysis: According to the staff audit, Jumper Creek's test year capital structure reflected common equity of $2,810 and customer deposits of $760.

The Utility's capital structure has been reconciled with staff's recommended rate base. The appropriate ROE for the Utility is 8.74 percent based upon the Commission-approved leverage formula currently in effect.[6] Staff recommends an ROE of 8.74 percent, with a range of 7.74 percent to 9.74 percent, and an overall rate of return of 8.62 percent. The ROE and overall rate of return are shown on Schedule No. 2.

[6] See Order No. PSC-14-0272-PAA-WS, issued May 29, 2014, in Docket No. 140006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

Issue 5: What are the appropriate test year revenues for the Utility's water and wastewater systems?

Recommendation: The appropriate test year revenues for Jumper Creek's water and wastewater systems are $13,370 and $20,662, respectively. (Thompson)

Staff Analysis: Jumper Creek recorded total test year water revenues of $13,078, which includes water service revenues of $11,746 and miscellaneous revenues of $1,332. The Utility recorded total test year wastewater revenues of $18,624. 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 for the water system should be increased by $980 to reflect total test year service revenues of $12,726. Staff adjusted miscellaneous revenues to reflect the appropriate amount of $1,288 and split it equally between water and wastewater. As a result, miscellaneous revenues should be decreased by $688 for water and increased by $644 for wastewater to reflect the appropriate miscellaneous revenues of $644 for each system during the test year. Therefore, staff recommends that the appropriate test year revenues for Jumper Creek's water and wastewater systems are $13,370 ($13,078 + $980 - $688) and $20,662 ($20,018 + $644), respectively. Test year revenues are shown on Schedule Nos. 3-A and 3-B.

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

Recommendation: The appropriate amount of total operating expense for the Utility is $20,095 for water and $27,024 for wastewater. (Vogel)

Staff Analysis: Jumper Creek recorded operating expense of $40,132 for water and $36,333 for wastewater for the test year ended June 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.

Purchased Power (615/715): The Utility recorded purchased power expense of $1,544 for water and $2,251 for wastewater. Two late fees were included in the wastewater invoices in this account. As a result, staff has decreased this account by $55 for wastewater. Therefore, staff recommends purchased power expense of $1,544 and $2,196 for water and wastewater, respectively.

Chemicals (618/718): The Utility recorded chemicals expense of $47 for water and $455 for wastewater. Staff believes no adjustments are necessary, and therefore recommends chemicals expense of $47 for water and $455 for wastewater.

Contractual Services - Professional (631/731): Jumper Creek recorded contractual services – professional expense of $1,250 for water and $2,083 for wastewater. The Utility included an invoice with no supporting documentation in the wastewater account; therefore, staff has decreased this account by $833. The resulting amounts for contractual services – professional expense are $1,250 for water and $1,250 for wastewater.

Contractual Services - Other (636/736): Jumper Creek recorded contractual services – other expense of $11,503 for water and $16,391 for wastewater. Staff has increased these accounts by $119 for water and $184 for wastewater. In addition, staff decreased the water account by $894 to remove an extra month of expenses in the water account.

Staff received letters from the Office of Public Counsel (OPC) and the Utility regarding the contract between the Utility and USWSC. After reviewing these letters, staff has adjusted the contract expenses for salaries, fuel, and vehicle maintenance. Staff's total adjustments to these expenses result in a decrease of $121 to water and $121 to wastewater.

USWSC provided its costing and allocation model to staff and OPC. Staff reviewed the model and its inputs and allocation procedures and, with the exception of the items for which staff has made adjustments, found the model to be reasonable. In particular, evaluation of the model revealed USWSC included 1,000 potential ERCs to its total ERCs served to spread the costs over a larger base. This lowers the cost per ERC. USWSC indicated it does this to recognize potential future ERCs that are expected to be added through growth or acquisitions. By spreading costs over multiple systems, and including potential ERCs to recognize potential future growth, Jumper Creek customers are realizing operational and cost benefits that would not be available if it operated on a stand-alone basis. In conclusion, staff believes the adjusted cost of the management services contract with USWSC is reasonable.

Staff's net adjustments are a decrease of $896 to water and an increase of $63 to wastewater. The resulting amounts for contractual services – other expense are $10,607 for water and $16,454 for wastewater.

Insurance Expense (655/755): Jumper Creek recorded insurance expense of $1,098 for water and $366 for wastewater for the test year. Staff has reduced insurance expense by $99 for lack of documentation. In addition, staff believes insurance expense should be allocated equally between the water and wastewater systems. Therefore, staff has split the remaining $1,365 between the two systems, $682 for water and $682 for wastewater. Staff's net adjustments decrease insurance expense for water by $416 and increase insurance expense for wastewater by $316. Therefore, staff recommends insurance expense for the test year of $682 for water and $682 for wastewater.

Regulatory Commission Expense (665/765): The Utility recorded regulatory commission expense of $118 for water and $118 for wastewater for the test year. This includes filing fees, noticing fees, and consulting fees. No adjustments were made to this account. Staff recommends regulatory commission expense of $118 for water and $118 for wastewater.

Bad Debt Expense (670/770): Jumper Creek recorded bad debt expense of $825 for water and $174 for wastewater. To establish an appropriate amount of bad debt expense for the test year, staff calculated a three year average using annual reports filed for the years 2012, 2013, and 2014. Using the three year average, staff recommends a decrease of $263 for water and an increase of $584 for wastewater. Therefore, staff recommends bad debt expense of $562 for water and $758 for wastewater.

Miscellaneous Expense (675/775): The Utility recorded miscellaneous expense of $2,120 for water and $657 for wastewater. Staff believes no adjustments are necessary, and therefore recommends miscellaneous expense of $2,120 for water and $657 for wastewater.

Operation and Maintenance Expenses Summary: Based on the above adjustments, staff recommends that the O&M expense balances are $17,778 for water and $24,377 for wastewater. Staff's recommended adjustments to O&M expense are shown on Schedule Nos. 3-A through 3-E.

Depreciation Expense (Net of Amortization of CIAC): The Utility recorded depreciation expense of $23,771 for water and $19,099 for wastewater during the test year. Staff recalculated depreciation expense using the prescribed rates set forth in Rule 25-30.140, F.A.C. Staff decreased depreciation expense by $4 for water and $40 for wastewater to reflect the appropriate depreciation expense. Also, staff decreased depreciation expense by $1,756 for water and $9,797 for wastewater to reflect the non-U&U portion of the test year depreciation expense. Jumper Creek recorded amortization expense of CIAC as $7,310 for water and $10,853 for wastewater during the test year. Staff also recalculated amortization of CIAC expense and decreased these accounts by $2,921 for water and $2,698 for wastewater to reflect the appropriate amount of this expense. Staff's net adjustments are an increase of $1,161 to water and a decrease of $7,139 to wastewater, resulting in a net depreciation expense of $17,622 ($23,771 – $7,310 + $1,161) for water and $1,107 ($19099 – $10,853 - $7,139) for wastewater. Staff is not including depreciation expense in its calculation of wastewater total operating expense.

Amortization Expense of the AA: Jumper Creek recorded no amortization expense of the AA. This expense for the test year was $1,125 for water and $572 for wastewater. The test year balances only capture one half of a month of this expense. Staff believes a full year of this expense should be used to reflect the appropriate amount of this expense moving forward. Therefore, staff has increased this amount to $20,143 for water and $10,249 for wastewater in place of the test year amounts. Also, to reflect the non-U&U portion of the test year amortization of AA expense, staff has decreased this account by $1,256 for water and $3,860 for wastewater. Staff's net adjustments are increases of $18,887 for water and $6,389 for wastewater. Staff recommends amortization expense of the AA of $18,887 for water and $6,389 for wastewater. Staff is not including amortization expense of the AA in its calculation of wastewater total operating expense.

Taxes Other Than Income (TOTI): Jumper Creek recorded a TOTI balance of $4,319 for water and $3,785 for wastewater. Staff has recalculated the Utility's ad valorem taxes using the updated 2014 rates and has decreased this account $1,113 for water and $843 for wastewater. Staff also included property tax expense for the pro forma plant additions resulting in an increase of $11 for wastewater. Staff has increased this account by $30 for water and $93 for wastewater to reflect the appropriate test year Regulatory Assessment Fees (RAFs) based on adjusted test year revenues. Also, to reflect the non-U&U portion of the test year TOTI expense, staff has decreased this account by $163 for water and $797 for wastewater.

In addition, as discussed in Issue 8, revenues have been increased by $11,313 for water and $8,799 for wastewater 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 $509 for water and $396 for wastewater to reflect RAFs of 4.5 percent on the recommended change in revenues. Staff's net adjustments are decreases of $737 for water and $1,140 for wastewater. Therefore, staff recommends TOTI of $3,582 and $2,646 for water and wastewater, respectively.

Operating Expenses Summary: The application of staff's recommended adjustments to Jumper Creek's test year operating expenses results in operating expenses of $20,095 for water and $27,024 for wastewater. Operating expenses are shown on Schedule Nos. 3-A and 3-B. The related adjustments are shown on Schedule Nos. 3-C, 3-D, and 3-E.

Issue 7: Should the Commission utilize the operating ratio methodology as an alternative means to calculate the wastewater revenue requirement for Jumper Creek, and, if so, what is the appropriate margin?

Recommendation: Yes, the Commission should utilize the operating ratio methodology for calculating the wastewater revenue requirement for Jumper Creek. The margin should be 10.00 percent of O&M expense. (Vogel)

Staff Analysis: Section 367.0814(9), F.S., provides that the Commission may, by rule, establish standards and procedures for setting rates and charges of small utilities using criteria other than those set forth in Sections 367.081(1), (2)(a), and (3), F.S. Rule 25-30.456, F.A.C., provides an alternative to a staff-assisted rate case as described in Rule 25-30.455, F.A.C. As an alternative, utilities with total gross annual operating revenue of less than $275,000 per system may petition the Commission for staff assistance using alternative rate setting.

Jumper Creek petitioned the Commission for alternative rate setting under the aforementioned rule and staff believes that the Commission should employ the operating ratio methodology to set rates in this case. The operating ratio methodology is an alternative to the traditional calculation of revenue requirements. Under this methodology, instead of applying a return on the Utility's rate base, the revenue requirement is based Jumper Creek's O&M expenses plus a margin. This methodology has been applied in cases in which the traditional calculation of the revenue requirement would not provide sufficient revenue to protect against potential variances in revenues and expenses.

By Order No. PSC-96-0357-FOF-WU, the Commission, for the first time, utilized the operating ratio methodology as an alternative means for setting rates.[7] This order also established criteria to determine the use of the operating ratio methodology and a guideline margin of 10.00 percent of O&M expense. This criterion was applied again in Order No. PSC-97-0130-FOF-SU.[8] Most recently, the Commission approved the operating ratio methodology for setting rates in Order No. PSC-13-0327-PAA-SU.[9]

By Order No. PSC-96-0357-FOF-WU, the Commission established criteria to determine whether to utilize the operating ratio methodology for those utilities with low or non-existent rate base. The qualifying criteria established by Order No. PSC-96-0357-FOF-WU and how they apply to the Utility are discussed below:

1) Whether the Utility's O&M expense exceeds rate base. The operating ratio method substitutes O&M expense for rate base in calculating the amount of return. A Utility generally would not benefit from the operating ratio method if rate base exceeds O&M expense. The decision to use the operating ratio method depends on the determination of whether the primary risk resides in capital costs or operating expenses. In the instant case, the wastewater rate base is less than the

[7] Issued March 13, 1996, in Docket No. 950641-WU, In re: Application for staff-assisted rate case in Palm Beach County by Lake Osborne Utilities Company, Inc.
[8] Issued February 10, 1997, in Docket No. 960561-SU, In re: Application for staff-assisted rate case in Citrus County by Indian Springs Utilities, Inc.
[9] Issued July 16, 2013, in Docket No. 120270-SU, In re: Application for staff-assisted rate case in Polk County by West Lakeland Wastewater, LLC.

level of O&M expense. The Utility's primary risk resides with covering its operating expense. Based on the staff's recommendation, the adjusted water and wastewater rate bases for the test year are $53,253 and a negative $12,038, while adjusted O&M expenses are $17,778 for water and $24,377 for wastewater.

2) Whether the Utility is expected to become a Class B utility in the foreseeable future. Pursuant to Section 367.0814(9), F.S., the alternative form of regulation being considered in this case only applies to small utilities with gross annual revenue of $250,000 or less. Jumper Creek is a Class C utility and the recommended revenue requirements of $24,683 and $29,461 are substantially below the threshold level for Class B status ($200,000 per system). The Utility's service area has not had any significant growth in the last five years. Therefore, the Utility will not become a Class B utility in the foreseeable future.

3) Quality of service and condition of plant. As discussed in Issue 1, staff recommends that the overall quality of service for the Jumper Creek water and wastewater systems in Sumter County is satisfactory.

4) Whether the Utility is developer-owned. The current Utility owner is not a developer.

5) Whether the Utility operates treatment facilities or is simply a distribution and/or collection system. The issue is whether purchased water and/or wastewater costs should be excluded in the computation of the operating margin. Jumper Creek operates water and wastewater treatment plants and collection systems.

Based on staff's review of the Utility's situation relative to the above criteria, staff recommends that Jumper Creek is a viable candidate for the operating ratio methodology.

By Order Nos. PSC-96-0357-FOF-WS and PSC-97-0130-FOF-WU, the Commission determined that a margin of 10.00 percent shall be used unless unique circumstances justify the use of a greater or lesser margin. The important question is not what the return percentage should be, but what level of operating margin will allow the utility to provide safe and reliable service and remain a viable entity. The answer to this question requires a great deal of judgment based upon the particular circumstances of the utility.

Several factors must be considered in determining the reasonableness of a margin. First, the margin must provide sufficient revenue for the Utility to cover its interest expense. Jumper Creek currently has no interest expense.

Second, use of the operating ratio methodology rests on the contention that the principal risk to the utility resides in operating cost rather than in cost of the plant. The fair return on a small rate base may not adequately compensate the utility owner for incurring the risk associated with covering the much larger operating cost. Therefore, the margin should adequately compensate the utility owner for that risk. Under the rate base methodology, the return to Jumper Creek would be $0 for wastewater. This would not provide the necessary financial margin to successfully operate this utility.

Also, if the return on rate base method was applied, the return would not generate sufficient revenue to cover operating expenses plus an adequate margin. Therefore, the operating ratio methodology should provide adequate revenue to cover operating costs at a minimum.

In this case, there is a large negative acquisition adjustment. Amortization of a negative AA reduces expenses. The significant size of the negative amortization expense results in a reduction in revenue requirements such that the revenue requirement is insufficient to cover the Utility's cash expenses. Further, staff removed depreciation from the operating ratio calculation. Prior Commission practice has been to include net depreciation expense in the operating ratio calculation. In this case, however, staff is recommending that net depreciation expense not be included in the operating ratio calculation. As staff is recommending removing the amortization expense of the AA from the calculation, consistent with that position, staff is also recommending removal of the net depreciation expense from the calculation.

O&M expenses and TOTI are cash expenses incurred by a utility to provide service, and as such must be recovered to ensure the continuity of safe and reliable service. Therefore, staff has only included these accounts in calculating the revenue requirement. These changes will provide Jumper Creek with adequate cash flow to provide safe and reliable service.

OPC's April 22, 2015 letter argues that variances in revenues and expenses are covered through the USWSC contract, the availability of pass-through applications, and indexes. The USWSC contract is cost-based and is not designed to absorb cost variances. The margin OPC refers to is not a margin for Jumper Creek, but for the contract operators. While USWSC and Jumper Creek share certain common investors, USWSC and Jumper Creek are not the same entity and Jumper Creek requires a margin to cover cost variances in its revenues and expenses. OPC also argues that the negative amortization expense from the acquisition adjustment should be included in the revenue requirement calculation. Staff notes that inclusion of this large non-cash expense will not allow the Utility to recover its O&M and TOTI expenses, which are cash expenses and must be paid through revenues. Staff does not agree with OPC on these issues and does not recommend these changes be made.

In conclusion, staff believes the above factors show that the Utility needs a higher margin of revenue over operating expenses than the traditional return on rate base method would allow. Therefore, in order to provide Jumper Creek with adequate cash flow to provide some assurance of safe and reliable service, staff recommends application of the operating ratio methodology at a margin of 10.00 percent of O&M expense for determining the wastewater revenue requirement.

Issue 8: What is the appropriate revenue requirement?

Recommendation: The appropriate revenue requirement is $24,683 for water and $29,461 for wastewater, resulting in an annual increase of $11,313 for water (84.62 percent), and an annual increase of $8,799 for wastewater (42.59 percent). (Vogel)

Staff Analysis: Jumper Creek should be allowed an annual increase of $11,313 for water (84.62 percent) and an annual increase of $8,799 for wastewater (42.59 percent). This will allow the Utility the opportunity to recover its expenses and earn an 8.62 percent return on its water system and allow the Utility to recover its O&M expenses, TOTI expenses, as well as allow it a 10.00 percent margin on those O&M expenses on its wastewater system. The calculations are shown in Tables 8-1 and 8-2 for water and wastewater, respectively:

Table 8-1
Water Revenue Requirement

Adjusted Rate Base	$53,253
Rate of Return	x 8.62%
Return on Rate Base	$4,588
Adjusted O&M Expense	17,778
Depreciation Expense (Net)	17,622
Amortization Expense of AA	(18,887)
Taxes Other Than Income	3,073
Test Year RAFs	509
Revenue Requirement	$24,683
Less Adjusted Test Year Revenues	13,370
Annual Increase	$11,313
Percent Increase	84.62%

Table 8-2
Wastewater Revenue Requirement

Adjusted O&M Expense	$24,377
Operating Margin (%)	10.00%
Operating Margin ($)	$2,438
Adjusted O&M Expense	24,377
Depreciation Expense (Net)	0
Amortization Expense of AA	0
Taxes Other Than Income	2,250
Test Year RAFs	396
Revenue Requirement	$29,461
Less Adjusted Test Year Revenues	20,662
Annual Increase	$8,799
Percent Increase	42.59%

Issue 9: What are the appropriate rate structures and rates for Jumper Creek's water and wastewater systems?

Recommendation: The recommended rate structures and monthly water and wastewater rates are shown on Schedule Nos. 4-A and 4-B, respectively. 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:

Water Rates

The Jumper Creek water system is located in Sumter County within the SWFWMD. The Utility provides water service to approximately 43 residential customers. Approximately 2.83 percent of the residential customer bills during the test year had zero gallons indicating a non-seasonal customer base. The average residential water demand is 4,566 gallons per month. Currently, the Utility's water rate structure consists of a monthly base facility charge (BFC) of $25.25, which includes an allotment of 10,000 gallons per month, and a gallonage charge of $2.52 for those gallons in excess of 10,000.

Staff performed an analysis of the Utility's billing data in order to evaluate various BFC cost recovery percentages and 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; and 3) implement, where appropriate, water conserving rate structures consistent with Commission practice.

A BFC and uniform gallonage charge is the preferred rate structure for residential water service. Staff recommends that 40 percent of the water revenues should be generated from the BFC, which will provide sufficient revenues to design a gallonage charge that will send an appropriate pricing signal to customers. Based on a recommended revenue increase of 88.9 percent and the removal of the 10,000 gallon allotment in the base facility charge, the residential consumption can be expected to decline by 282,000 gallons resulting in anticipated average residential demand of 3,996 gallons per month. Staff recommends a 12.48 percent reduction in total residential consumption and corresponding reductions of $193 for purchased power, $6 for chemicals, and $9 for RAFs to reflect the anticipated repression, which results in a post repression revenue requirement of $23,831.

Based on the foregoing, staff recommends 40 percent of the water revenues be generated from the BFC. The traditional BFC and uniform gallonage charge rate structure should be approved for residential and general service water customers. A 12.48 percent reduction in total residential consumption and corresponding reductions of $193 for purchased power, $6 for

chemicals, and $9 for RAFs should be made to reflect the anticipated repression. Staff's recommended rate structure and the resulting wastewater rates are shown on Schedule Nos. 4-A.

Wastewater Rates

The Utility also provides wastewater service to its 43 residential customers. Currently, the wastewater rate structure consists of a monthly flat rate of $40.44 for all customer classes. Staff performed an analysis of the Utility's billing data in order to evaluate various BFC cost recovery percentages and gallonage caps for the residential wastewater 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.

A BFC and gallonage charge with cap is the preferred rate structure for residential wastewater service. Since metered water usage is available, staff believes the flat rate structure should be discontinued. Typically, the Commission's practice is to allocate at least 50 percent of the wastewater revenue requirement to the BFC due to the capital intensive nature of wastewater plants. Based on the significant increase in the revenue requirement, staff recommends that 50 percent of the revenue requirement should be generated from the BFC in order to mitigate the impact of the rate increase.

The gallonage cap recognizes that not all water used by residential customers is returned to the wastewater system. The cap creates the maximum amount a residential customer would pay for wastewater service. Typically, the residential wastewater cap is set at approximately 80 percent of the water demand. Based on the Utility's billing analysis, the 6,000 gallon level is where approximately 80 percent of water demand is captured. Therefore, staff recommends the gallonage cap should be set at 6,000 gallons.

In addition, based on the expected reduction in water demand described above, staff recommends that a repression adjustment also be made for wastewater. Because wastewater rates are calculated based on customers' water demand, if those customers' water demand is expected to decline, then the billing determinants used to calculate wastewater rates should also be adjusted. Therefore, staff recommends that a repression adjustment should also be made to calculate wastewater rates. Based on the billing analysis for the wastewater system, staff recommends a repression adjustment of 93,757 gallons to reflect the anticipated reduction in water demand used to calculate wastewater rates. Staff recommends a 4.69 percent reduction in total residential consumption and corresponding reductions of $103 for purchased power, $21 for chemicals, $45 for sludge removal, and $8 for RAFs to reflect the anticipated repression, which results in a post repression revenue requirement of $28,639.

Based on the above, staff recommends a discontinuance of the flat rate structure for wastewater customers. Staff recommends that the residential wastewater customers' rate structure should consist of a BFC for all meter sizes, based on a 50 percent allocation of wastewater revenue to the BFC, with a cap of 6,000 gallons. A 4.69 percent reduction in total residential consumption and corresponding reductions of $103 for purchased power, $21 for

chemicals, $45 for sludge removal, and $8 for RAFs should be made to reflect the anticipated repression. 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. Staff's recommended rate structure and the resulting wastewater rates are shown on Schedule Nos. 4-B.

Summary

Staff recommends the Commission approve the monthly water and wastewater rates and rate structure are shown on Schedule Nos. 4-A and 4-B, respectively. 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 10: In determining whether any portion of the interim increase granted should be refunded, how should the refund be calculated, and what is the amount of the refund, if any?

Recommendation: The proper refund amount should be calculated by using the same data used to establish final rates, excluding pro forma and other items not in effect during the interim period. This revised revenue requirement for the interim collection period should be compared to the amount of interim revenue requirement granted. Based on this calculation, no refunds are required. Further, upon issuance of the Consummating Order in this docket, the surety bond should be released. (Vogel)

Staff Analysis: By Order No. PSC-14-0596-PCO-WS, issued October 22, 2014, the Commission authorized the collection of interim water and wastewater rates, subject to refund, pursuant to Section 367.082, F.S. The approved interim revenue requirement was $24,020 and $18,998 for water and wastewater, respectively, which represents an increase of $10,942 or 83.67 percent for water and $374 or 2.01 percent for wastewater.

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.

In this proceeding, the test period for establishment of interim and final rates is the 12-month period ended June 30, 2014. Jumper Creek's approved interim rates did not include any provisions for pro forma or projected operating expenses or plant. The interim increase was designed to allow recovery of total operating expenses.

To establish the proper refund amount, staff has calculated a revised interim revenue requirement utilizing the same data used to establish final rates. Using the principles discussed above, the revenue requirements of $24,020 for water and the $18,998 for wastewater granted in Order No. PSC-14-0596-PCO-WS is less than the revised revenue requirement for the interim collection period of $24,683 for water and $29,461 for wastewater. As such, staff recommends that no refund is required for revenues collected under interim rates. Further, upon issuance of the Consummating Order in this docket, the surety bond should be released.

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 and wastewater rates should be reduced as shown on Schedule Nos. 4-A and 4-B, to remove rate case expense grossed-up for RAFs 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. Jumper Creek 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. (Vogel, Thompson)

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 reductions are $125 and $136 for water and wastewater, respectively.

The water and wastewater rates should be reduced as shown on Schedule Nos. 4-A and 4-B to remove rate case expense grossed-up for RAFs 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. Jumper Creek 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: What are the appropriate initial customer deposits for Jumper Creek?

Recommendation: The appropriate initial customer deposits should be $96 and $118 for the residential 5/8″ x 3/4″ meter size for water and wastewater, respectively. 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 water and 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. (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.[10] Currently, the Utility's existing initial deposits for residential 5/8″ x 3/4" meters are $50 for water and $80 for wastewater. Based on staff's recommended rates, the appropriate initial customer deposit should be $96 for water and $118 for wastewater to reflect an average residential customer bill for two months.

Staff recommends the appropriate initial customer deposits should be $96 and $118 for the residential 5/8″ x 3/4″ meter size for water and wastewater, respectively. 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 water and 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.

[10] See Order No. PSC-14-0508-AS-WS, issued September 24, 2014, in Docket No. 130212-WS, In re: Application for increase in water/wastewater rates in Polk County by Cypress Lakes Utilities, Inc.

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 should 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. Jumper Creek 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's Office of Commission Clerk 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. (Vogel)

Staff Analysis: This recommendation proposes an increase in water and wastewater 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. Jumper Creek 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 $13,411. 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) No monies in the escrow account may be withdrawn by the Utility without the express approval of the Commission;
2) The escrow account shall be an interest bearing account;
3) If a refund to the customers is required, all interest earned by the escrow account shall be distributed to the customers;
4) If a refund to the customers is not required, the interest earned by the escrow account shall revert to the Utility;
5) All information on the escrow account shall be available from the holder of the escrow account to a Commission representative at all times;
6) The amount of revenue subject to refund shall be deposited in the escrow account within seven days of receipt;
7) 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;
8) The Commission Clerk must be a signatory to the escrow agreement; and,
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 security, 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's Office of Commission Clerk 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 provide proof, within 90 days of an effective order finalizing this docket, that it has adjusted its books for all applicable National Association of Regulatory Commissioners Uniform System of Accounts (NARUC USOA) primary accounts associated with the Commission approved adjustments?

Recommendation: Yes. To ensure that the Utility adjusts its books in accordance with the Commission's decision, Jumper Creek should provide proof, within 90 days of the final order in this docket, that the adjustments for all applicable NARUC USOA primary accounts have been made. (Vogel)

Staff Analysis: To ensure that the Utility adjusts its books in accordance with the Commission's decision, Jumper Creek should provide proof, within 90 days of the final order in this docket, that the adjustments for all applicable NARUC USOA primary accounts have been made.

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 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. (Tan)

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.

JUMPER CREEK UTILITY COMPANY **SCHEDULE NO. 1-A**
TEST YEAR ENDED 06/30/14 **DOCKET NO. 140147-WS**
SCHEDULE OF WATER RATE BASE

DESCRIPTION	BALANCE PER UTILITY	STAFF ADJUSTMENTS TO UTIL. BAL.	BALANCE PER STAFF
UTILITY PLANT IN SERVICE	$511,881	$0	$511,881
LAND & LAND RIGHTS	2,272	0	2,272
NON-USED AND USEFUL COMPONENTS	0	(9,095)	(9,095)
CIAC	(157,236)	0	(157,236)
ACCUMULATED DEPRECIATION	(151,215)	11,885	(139,330)
AMORTIZATION OF CIAC	38,790	(8,625)	30,166
ACQUISITION ADJUSTMENT	(208,895)	0	(208,895)
ACCUMULATED DEPRECIATION OF AA	0	21,268	21,268
WORKING CAPITAL ALLOWANCE	0	2,222	2,222
WATER RATE BASE	$35,597	$17,656	$53,253

JUMPER CREEK UTILITY COMPANY **SCHEDULE NO. 1-B**
TEST YEAR ENDED 06/30/14 **DOCKET NO. 140147-WS**
SCHEDULE OF WASTEWATER RATE BASE

DESCRIPTION	BALANCE PER UTILITY	STAFF ADJUSTMENTS TO UTIL. BAL.	BALANCE PER STAFF
UTILITY PLANT IN SERVICE	$389,284	$965	$390,249
LAND & LAND RIGHTS	18,722	0	18,722
NON-USED AND USEFUL COMPONENTS	(128,851)	81,606	(47,245)
CIAC	(221,828)	0	(221,828)
ACCUMULATED DEPRECIATION	(126,053)	10,927	(115,126)
AMORTIZATION OF CIAC	54,724	(547)	54,177
ACQUISITION ADJUSTMENT	(104,855)	0	(104,855)
ACCUMULATED DEPRECIATION OF AA	0	10,821	10,821
WORKING CAPITAL ALLOWANCE	0	3,047	3,047
WASTEWATER RATE BASE	($118,857)	$106,819	($12,038)

JUMPER CREEK UTILITY COMPANY TEST YEAR ENDED 06/30/14 ADJUSTMENTS TO RATE BASE		SCHEDULE NO. 1-C DOCKET NO. 140147-WS PAGE 1 OF 1
	WATER	**WASTEWATER**
UTILITY PLANT IN SERVICE		
1. To reflect pro forma additions.	$0	$3,860
2. To reflect retirements associated with pro forma additions.	0	(2,895)
Total	$0	$965
NON-USED AND USEFUL PLANT		
1. To reflect non-used and useful plant.	$(31,926)	$53,254
2. To reflect non-used and useful accumulated depreciation.	11,129	(7,065)
3. To reflect non-used and useful acquisition adjustment.	13,029	39,492
4. To reflect non-used and useful amortization of acquisition adjustment.	(1,326)	(4,076)
Total	$(9,095)	$81,606
ACCUMULATED DEPRECIATION		
1. To reflect an averaging adjustment.	$11,885	$8,097
2. To reflect appropriate Acc. Dep. associated with pro forma plant.	0	2,830
Total	$11,885	$10,927
AMORTIZATION OF CIAC		
1. To reflect the appropriate amount of amortization.	($6,430)	$3,531
2. To reflect an averaging adjustment.	(2,195)	(4,078)
Total	($8,625)	($547)
AMORTIZATION OF ACQUISTION ADJUSTMENT		
1. To reflect the amount of amortization of AA during the test year.	$1,125	$572
2. To normalize the appropriate amount of amortization of AA.	20,143	10,249
Total	$21,268	$10,821
WORKING CAPITAL ALLOWANCE		
To reflect 1/8 of test year O&M expenses.	$2,222	$3,047

JUMPER CREEK UTILITY COMPANY **SCHEDULE NO. 2**
TEST YEAR ENDED 06/30/14 **DOCKET NO. 140147-WS**
SCHEDULE OF CAPITAL STRUCTURE

	CAPITAL COMPONENT	PER UTILITY	SPECIFIC ADJUST-MENTS	BALANCE BEFORE PRO RATA ADJUSTMENTS	PRO RATA ADJUST-MENTS	BALANCE PER STAFF	PERCENT OF TOTAL	COST	WEIGHTED COST
1.	COMMON EQUITY	$2,810	$0	$2,810	$37,646	$40,456	98.16%	8.74%	8.58%
2.	LONG-TERM DEBT	0	0	0	0	0	0.00%	0.00%	0.00%
3.	SHORT-TERM DEBT	0	0	0	0	0	0.00%	0.00%	0.00%
4.	PREFERRED STOCK	0	0	0	0	0	0.00%	0.00%	0.00%
5.	CUSTOMER DEPOSITS	760	0	760	0	760	1.84%	2.00%	0.04%
6.	DEFERRED INCOME TAXES	0	0	$0	0	$0	0.00%	0.00%	0.00%
7.	TOTAL	$3,570	$0	$3,570	$37,646	$41,216	100.00%	10.74%	8.62%

RANGE OF REASONABLENESS	LOW	HIGH
RETURN ON EQUITY	7.74%	9.74%
OVERALL RATE OF RETURN	7.63%	9.60%

JUMPER CREEK UTILITY COMPANY **SCHEDULE NO. 3-A**
TEST YEAR ENDED 06/30/14 **DOCKET NO. 140147-WS**
SCHEDULE OF WATER OPERATING INCOME

	TEST YEAR PER UTILITY	STAFF ADJUSTMENTS	STAFF ADJUSTED TEST YEAR	ADJUST. FOR INCREASE	REVENUE REQUIREMENT
1. **OPERATING REVENUES**	$13,078	$292	$13,370	$11,313	$24,683
				84.62%	
OPERATING EXPENSES:					
2. OPERATION & MAINTENANCE	$19,352	($1,574)	$17,778	$0	$17,778
3. DEPRECIATION (NET)	16,461	1,161	17,622	0	17,622
4. AMORTIZATION OF AA	0	(18,887)	(18,887)	0	(18,887)
5. TAXES OTHER THAN INCOME	4,319	(1,246)	3,073	509	3,582
6. INCOME TAXES	0	0	0	0	0
7. **TOTAL OPERATING EXPENSES**	$40,132	($20,546)	$19,586	$509	$20,095
8. **OPERATING INCOME/(LOSS)**	($27,054)		($6,216)		$4,588
9. **WATER RATE BASE**	$35.597		$53,253		$53,253
10. **RATE OF RETURN**			(11.67%)		8.62%

JUMPER CREEK UTILITY COMPANY **SCHEDULE NO. 3-B**
TEST YEAR ENDED 06/30/14 **DOCKET NO. 140147-WS**
SCHEDULE OF WASTEWATER OPERATING INCOME

	TEST YEAR PER UTILITY	STAFF ADJUSTMENTS	STAFF ADJUSTED TEST YEAR	ADJUST. FOR INCREASE	REVENUE REQUIREMENT
1. **OPERATING REVENUES**	$18,624	$2,038	$20,662	$8,799	$29,461
				42.59%	
OPERATING EXPENSES:					
2. OPERATION & MAINTENANCE	$24,302	$75	$24,377	$0	$24,377
3. DEPRECIATION (NET)	8,246	(7,139)	1,107	(1,107)	0
4. AMORTIZATION OF AA	0	(6,389)	(6,389)	6,389	0
5. TAXES OTHER THAN INCOME	3,785	(1,535)	2,250	396	2,646
6. INCOME TAXES	0	0	0	0	0
7. **TOTAL OPERATING EXPENSES**	$36,333	($14,987)	$21,346	$5,678	$27,024
8. **OPERATING INCOME/(LOSS)**	($17,709)		($684)		$2,438
9. **WASTEWATER O&M EXPENSES**	$24.377		$24,377		$24,377
10. **OPERATING RATIO ON O&M EXPENSES**					10.00%

	JUMPER CREEK UTILITY COMPANY TEST YEAR ENDED 06/30/14 ADJUSTMENTS TO OPERATING INCOME	SCHEDULE NO. 3-C DOCKET NO. 140147-WS	
		WATER	**WASTEWATER**
	OPERATING REVENUES		
1.	To reflect the appropriate test year services revenues.	$980	$1,394
2.	To reflect miscellaneous revenues.	(688)	644
	Subtotal	$292	$2,038
	OPERATION AND MAINTENANCE EXPENSES		
1.	Purchased Power (615/715)		
	To reflect the appropriate amount of chemicals for the test year.	$0	($55)
	Subtotal	$0	($55)
2.	Contractual Services – Professional (631/731)		
	To remove unsupported invoices.	$0	($833)
	Subtotal	$0	($833)
3.	Contractual Services - Other (636/736)		
	a. To exclude the month of July 2014.	($894)	$0
	b. To reflect the appropriate amount of Contractual Services – Other.	119	184
	c. To reflect administrative contract adjustments.	(121)	(121)
	Subtotal	($896)	$63
4.	Insurance Expense (655/755)		
	a. To reflect appropriate insurance expense.	($416)	$316
	Subtotal	($416)	$316
5.	Bad Debt Expense (670/770)		
	a. To reflect the 3 year average of bad debt expense.	($263)	$584
	Subtotal	($263)	$584
	TOTAL OPERATION & MAINTENANCE ADJUSTMENTS	($1,575)	$75
	DEPRECIATION EXPENSE		
1.	To reflect appropriate depreciation expense.	($4)	($40)
2.	To reflect non-used and useful depreciation expense.	(1,756)	(9,797)
3.	To reflect the appropriate amount of amortization expense of CIAC.	2,921	2,698
	Total	$1,161	($7,139)
	AMORTIZATION EXPENSE OF AA		
1.	To reflect the appropriate amount of amortization expense of AA.	($20,143)	($10,249)
2.	To reflect the non-used and useful amortization expense of AA.	1,256	3,860
	Total	($18,887)	($6,389)
	TAXES OTHER THAN INCOME		
1.	To reflect the appropriate test year RAFs.	$30	$93
2.	To reflect non-used and useful property taxes.	(163)	(797)
3.	To reflect the appropriate test year property taxes.	(1,113)	(842)
4.	To reflect the appropriate allocation of property taxes to plant additions.	0	11
	Total	($1,246)	($1,535)

JUMPER CREEK UTILITY COMPANY — **SCHEDULE NO. 3-D**
TEST YEAR ENDED 06/30/14 — **DOCKET NO. 140147-WS**
ANALYSIS OF WATER OPERATION AND MAINTENANCE EXPENSE

	TOTAL PER UTILITY	STAFF ADJUST-MENTS	TOTAL PER STAFF
(601) SALARIES AND WAGES - EMPLOYEES	$0	$0	$0
(603) SALARIES AND WAGES - OFFICERS	750	0	750
(604) EMPLOYEE PENSIONS AND BENEFITS	0	0	0
(610) PURCHASED WATER	0	0	0
(615) PURCHASED POWER	1,544	0	1,544
(616) FUEL FOR POWER PRODUCTION	0	0	0
(618) CHEMICALS	47	0	47
(620) MATERIALS AND SUPPLIES	0	0	0
(630) CONTRACTUAL SERVICES - BILLING	0	0	0
(631) CONTRACTUAL SERVICES - PROFESSIONAL	1,250	0	1,250
(633) CONTRACTUAL SERVICES - LEGAL	98	0	98
(636) CONTRACTUAL SERVICES - OTHER	11,503	(896)	10,607
(640) RENTS	0	0	0
(650) TRANSPORTATION EXPENSE	0	0	0
(655) INSURANCE EXPENSE	1,098	(416)	682
(665) REGULATORY COMMISSION EXPENSE	118	0	118
(670) BAD DEBT EXPENSE	825	(263)	562
(675) MISCELLANEOUS EXPENSE	2,120	0	2,120
	$19,353	($1,575)	$17,778

JUMPER CREEK UTILITY COMPANY **SCHEDULE NO. 3-E**

TEST YEAR ENDED 06/30/14 **DOCKET NO. 140147-WS**

ANALYSIS OF WASTEWATER OPERATION AND MAINTENANCE EXPENSE

	TOTAL PER UTILITY	STAFF ADJUST-MENTS	TOTAL PER STAFF
(701) SALARIES AND WAGES - EMPLOYEES	$0	$0	$0
(703) SALARIES AND WAGES - OFFICERS	750	0	750
(704) EMPLOYEE PENSIONS AND BENEFITS	0	0	0
(710) PURCHASED SEWAGE TREATMENT	0	0	0
(711) SLUDGE REMOVAL EXPENSE	959	0	959
(715) PURCHASED POWER	2,251	(55)	2,196
(716) FUEL FOR POWER PRODUCTION	0	0	0
(718) CHEMICALS	455	0	455
(720) MATERIALS AND SUPPLIES	0	0	0
(730) CONTRACTUAL SERVICES - BILLING	0	0	0
(731) CONTRACTUAL SERVICES - PROFESSIONAL	2,083	(833)	1,250
(735) CONTRACTUAL SERVICES - LEGAL	98	0	98
(736) CONTRACTUAL SERVICES - OTHER	16,391	63	16,454
(740) RENTS	0	0	0
(750) TRANSPORTATION EXPENSE	0	0	0
(755) INSURANCE EXPENSE	366	316	682
(765) REGULATORY COMMISSION EXPENSE	118	0	118
(770) BAD DEBT EXPENSE	174	584	758
(775) MISCELLANEOUS EXPENSE	657	0	657
	$24,302	$75	$24,377

JUMPER CREEK UTILITY COMPANY
TEST YEAR ENDED JUNE 30, 2014 **SCHEDULE NO. 4-A**
MONTHLY WATER RATES **DOCKET NO. 140147-WS**

	RATES AT TIME OF FILING	COMMISSION APPROVED INTERIM RATES	STAFF RECOMMENDED RATES	4 YEAR RATE REDUCTION
Residential and General Service				
Base Facility Charge for All Meter Sizes	$25.25	$48.77	N/A	N/A
Base Facility Charge by Meter Size				
5/8" x 3/4"	N/A	N/A	$19.26	$0.10
3/4"	N/A	N/A	$28.89	$0.15
1"	N/A	N/A	$48.15	$0.25
1-1/2"	N/A	N/A	$96.30	$0.50
2"	N/A	N/A	$154.08	$0.81
3"	N/A	N/A	$308.16	$1.61
4"	N/A	N/A	$481.50	$2.52
6"	N/A	N/A	$963.00	$5.05
8"	N/A	N/A	$1,540.80	$8.07
Charge per 1,000 gallons	N/A	N/A	$7.23	$0.04
0 - 10,000 gallons	$0.00	$0.00	N/A	N/A
Over 10,000 gallons	$2.52	$4.87	N/A	N/A
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
4,000 Gallons	$25.25	$48.77	$48.18	
6,000 Gallons	$25.25	$48.77	$62.64	
10,000 Gallons	$25.25	$48.77	$91.56	

JUMPER CREEK UTILITY COMPANY
TEST YEAR ENDED JUNE 30, 2014 **SCHEDULE NO. 4-B**
MONTHLY WASTEWATER RATES **DOCKET NO. 140147-WS**

	RATES AT TIME OF FILING	COMMISSION APPROVED INTERIM RATES	STAFF RECOMMENDED RATES	4 YEAR RATE REDUCTION
Residential Service				
Flat Rate	$40.44	$41.25	N/A	N/A
Base Facility Charge for All Meter Sizes	N/A	N/A	$29.11	$0.14
Charge per 1,000 gallons	N/A	N/A	$7.46	$0.04
6,000 gallon cap				
General Service				
Flat Rate	$40.44	$41.25	N/A	N/A
Base Facility Charge by Meter Size				
5/8"X3/4"	N/A	N/A	$29.11	$0.14
3/4"	N/A	N/A	$43.67	$0.21
1"	N/A	N/A	$72.78	$0.35
1-1/2"	N/A	N/A	$145.55	$0.69
2"	N/A	N/A	$232.88	$1.11
3"	N/A	N/A	$465.76	$2.21
4"	N/A	N/A	$727.75	$3.45
6"	N/A	N/A	$1,455.50	$6.91
8"	N/A	N/A	$2,328.80	$11.05
Charge per 1,000 gallons	N/A	N/A	$8.95	$0.04
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
4,000 Gallons	$40.44	$41.25	$58.95	
6,000 Gallons	$40.44	$41.25	$73.87	
10,000 Gallons	$40.44	$41.25	$73.87	

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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Accounting and Finance (D. Buys, Cicchetti)
Office of the General Counsel (Janjic, Mapp)

RE: Docket No. 150006-WS – Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

AGENDA: 06/18/15 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Graham

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

Section 367.081(4)(f), Florida Statutes (F.S.), authorizes the Commission to establish, not less than once each year, a leverage formula to calculate a reasonable range of returns on equity (ROE) for water and wastewater (WAW) utilities. The leverage formula methodology currently in use was established in Order No. PSC-01-2514-FOF-WS.[1] On October 23, 2008, the Commission held a formal hearing in Docket No. 080006-WS to allow interested parties to provide testimony regarding the validity of the leverage formula.[2] Based on the record in that

[1] Order No. PSC-01-2514-FOF-WS, issued December 24, 2001, in Docket No. 010006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[2] At the May 20, 2008, Commission Conference, upon request of the Office of Public Counsel, the Commission voted to set the establishment of the appropriate leverage formula directly for hearing.

proceeding, the Commission approved the 2008 leverage formula in Order No. PSC-08-0846-FOF-WS.[3] In that order, the Commission reaffirmed the methodology that was previously approved in Order No. PSC-01-2514-FOF-WS.

Staff continues to use the leverage formula methodology established in Order No. PSC-01-2514-FOF-WS and reaffirmed in Order No. PSC-08-0846-FOF-WS. This methodology uses ROEs derived from financial models applied to an index of natural gas utilities. Based on the results of staff's annual review, there are an insufficient number of WAW utilities that meet the requisite criteria to assemble an appropriate proxy group using only WAW utilities. Therefore, since 2001, the Commission has used natural gas utilities as the proxy companies for the leverage formula. There are many natural gas utilities that have actively traded stocks and forecasted financial data. Staff uses natural gas utilities that derive at least 50 percent of their revenue from regulated rates. These utilities have market power and are influenced significantly by economic regulation. As explained in Issue 1, the model results based on natural gas utilities are adjusted to reflect the risks faced by Florida WAW utilities.

In 2011, the Commission approved the leverage formula currently in effect (2011 leverage formula) by Order No. PSC-11-0287-PAA-WS.[4] In 2012, 2013, and 2014, the Commission approved staff's recommendations to continue to use the 2011 leverage formula for establishing the authorized ROE for WAW utilities by Order Nos. PSC-12-0339-PAA-WS,[5] PSC-13-0241-PAA-WS,[6] and PSC-14-0272-PAA-WS.[7] In 2012, 2103, and 2014, the Commission found that the range of returns on equity derived from the leverage formulas were not optimal for determining the appropriate authorized ROE for WAW utilities due to Federal Reserve monetary policies that resulted in historically low interest rates. Consequently, the Commission decided that the range of returns on equity of 8.74 percent to 11.16 percent from the 2011 leverage formula was more reasonable.

Additional precedent for continuing the use of the current leverage formula occurred in 1996 when staff recommended, and the Commission voted, to continue to base the authorized ROE for WAW utilities on the leverage formula instituted in 1995.[8] In Order No. PSC-96-0729-

[3] Order No. PSC-08-0846-FOF-WS, issued December 31, 2008, in Docket No. 080006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[4] Order No. PSC-11-0287-PAA-WS, issued July 5, 2011, in Docket No. 110006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[5] Order No. PSC-12-0339-PAA-WS, issued June 28, 2012, in Docket No. 120006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[6] Order No. PSC-13-0241-PAA-WS, issued June 3, 2013, in Docket No. 130006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[7] Order No. PSC-14-0272-PAA-WS, issued May 29, 2014, in Docket No. 140006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.

[8] Order No. PSC-96-0729-FOF-WS, issued May 31, 1996, in Docket No. 960006-WS, In re: Annual reestablishment of authorized range of returns on common equity of water and wastewater utilities, pursuant to Section 367.081(4)(f), F.S.

FOF-WS, the Commission found that the leverage formula range of returns from the prior year were still reasonable and found it appropriate to continue to base the authorized range of returns on common equity for WAW utilities on the leverage formula from the prior year.

Although Section 367.081(4)(f), F.S., authorizes the Commission to establish a range of returns for setting the authorized ROE for WAW utilities, the Commission may set an ROE for WAW utilities based on record evidence in any proceeding. If one or more parties file testimony in opposition to the use of the leverage formula, the Commission will determine the appropriate ROE based on the evidentiary record in that proceeding.

The Commission has jurisdiction pursuant to Section 367.081, F.S.

Discussion of Issues

Issue 1: What is the appropriate range of returns on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), Florida Statutes?

Recommendation: Staff recommends that the current leverage formula approved by the Commission in Order No. PSC-14-0272-PAA-WS continue to be used until the leverage formula is readdressed in 2016. Accordingly, staff recommends the following leverage formula:

Return on Common Equity = 7.13% + (1.610 ÷ Equity Ratio)

Where the Equity Ratio = Common Equity ÷ (Common Equity + Preferred Equity + Long-Term and Short-Term Debt)

Range: 8.74% @ 100% equity to 11.16% @ 40% equity

Additionally, staff recommends that the Commission cap returns on common equity at 11.16 percent for all WAW utilities with equity ratios less than 40 percent. Staff believes this will discourage imprudent financial risk. This cap is consistent with the methodology in Order No. PSC-08-0846-FOF-WS. (D. Buys)

Staff Analysis: Section 367.081(4)(f), F.S., authorizes the Commission to establish a leverage formula to calculate a reasonable range of returns on common equity for WAW utilities. The Commission must establish this leverage formula not less than once a year.

In 2014, by Order No. PSC-14-0272-PAA-WS, the Commission approved staff's recommendation to continue to use the leverage formula initially approved in 2011. The Commission kept the 2011 leverage formula in place because Federal Reserve monetary policies lowered interest rates to historically low levels, thereby increasing the slope of the leverage formula graph relative to previous years. The Federal Reserve's monetary policies and resulting capital market conditions that existed in 2012 through 2014 are expected to continue in 2015.[9]

In the instant docket, staff updated the leverage formula using the most recent 2015 financial data and the Commission approved methodology. Using the updated financial data in the leverage formula decreases the lower end of the current allowed ROE range by 95 basis points while increasing the upper end of the range by 35 basis points relative to the current leverage formula. The spread between the range of returns on equity based on the updated leverage formula is 372 basis points (7.79 percent to 11.51 percent). This is the second largest spread for the allowed ROE for WAW utilities in the approximately 33 years the leverage formula has been in use in Florida. In comparison, the spread in the range of returns on equity for the existing leverage formula is 242 basis points (8.74 percent to 11.16 percent).

The increase in the spread in the range of the ROE from the updated leverage formula relative to the 2011 leverage formula is caused by the very low bond rates resulting from the

[9] See Federal Reserve System, minutes of the Federal Open Market Committee on April 28-29, 2015, p. 10, available at http://www.federalreserve.gov/monetarypolicy/files/fomcminutes20150429.pdf.

Federal Reserve's various monetary policies and quantitative easing programs, which are still in effect. In its press release dated April 29, 2015, the Federal Reserve stated:

> To support continued progress toward maximum employment and price stability, the Committee today reaffirmed its view that the current 0 to 1/4 percent target range for the federal funds rate remains appropriate. In determining how long to maintain this target range, the Committee will assess progress--both realized and expected--toward its objectives of maximum employment and 2 percent inflation. This assessment will take into account a wide range of information, including measures of labor market conditions, indicators of inflation pressures and inflation expectations, and readings on financial and international developments. The Committee anticipates that it will be appropriate to raise the target range for the federal funds rate when it has seen further improvement in the labor market and is reasonably confident that inflation will move back to its 2 percent objective over the medium term.[10]

In the same press release, the Federal Reserve further stated:

> When the Committee decides to begin to remove policy accommodation, it will take a balanced approach consistent with its longer-run goals of maximum employment and inflation of 2 percent. The Committee currently anticipates that, even after employment and inflation are near mandate-consistent levels, economic conditions may, for some time, warrant keeping the target federal funds rate below levels the Committee views as normal in the longer run.

The most recent assumed Baa3 bond rate of 5.31 percent used in the updated leverage formula calculation, which includes a 50 basis point adjustment for small company risk and a 50 basis point adjustment for a private placement premium, remains low relative to historic levels. In comparison, the assumed Baa3 bond rate used in the existing leverage formula is 7.13 percent.

Because interest rates are at historically low levels, thereby increasing the slope of the leverage formula relative to prior years, staff believes the range of returns on equity produced from the updated leverage formula is not optimal for determining the appropriate authorized ROE for Florida WAW utilities at this time. An increase in the slope of the leverage formula means a given change in the equity ratio will result in a greater change to the cost of equity. The results of this year's leverage formula produced a slope consistent with the slopes produced by financial data for 2012 through 2014. As shown on the following page, Chart 1-1 illustrates the change in the slope of the leverage formula using updated data compared to the current leverage formula.

[10] See Federal Reserve System, Monetary Policy Releases, available at http://www.federalreserve.gov/newevents/press/monetary/ 20150429a.htm.

Chart 1-1

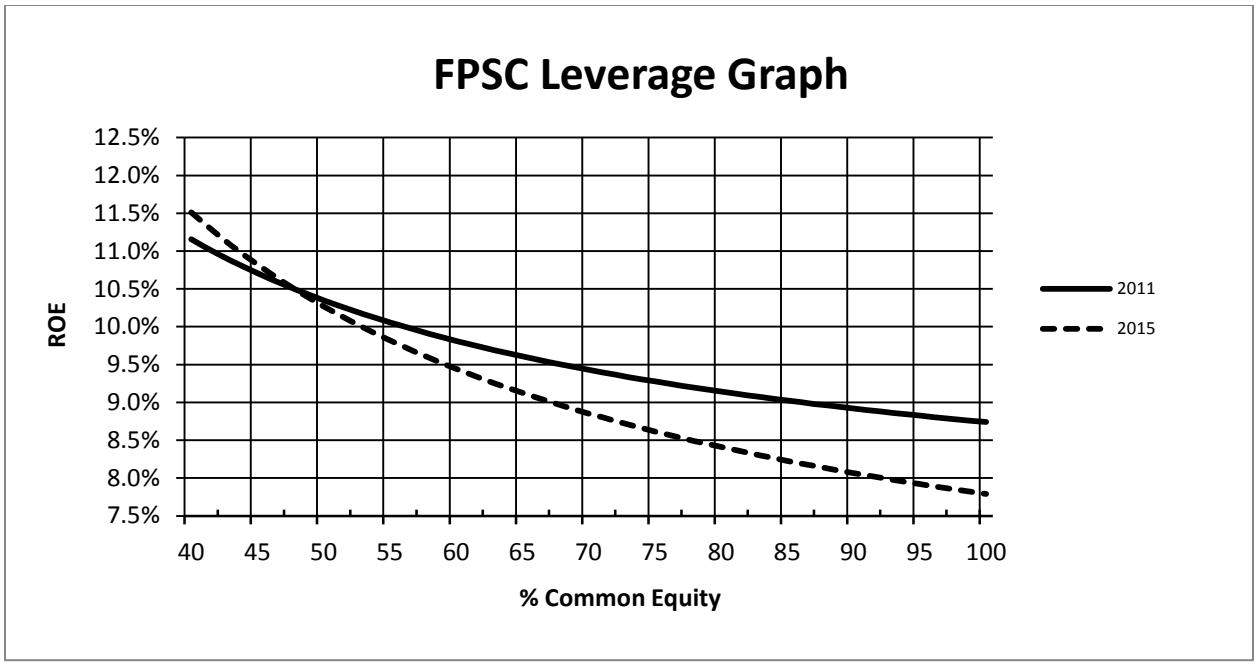
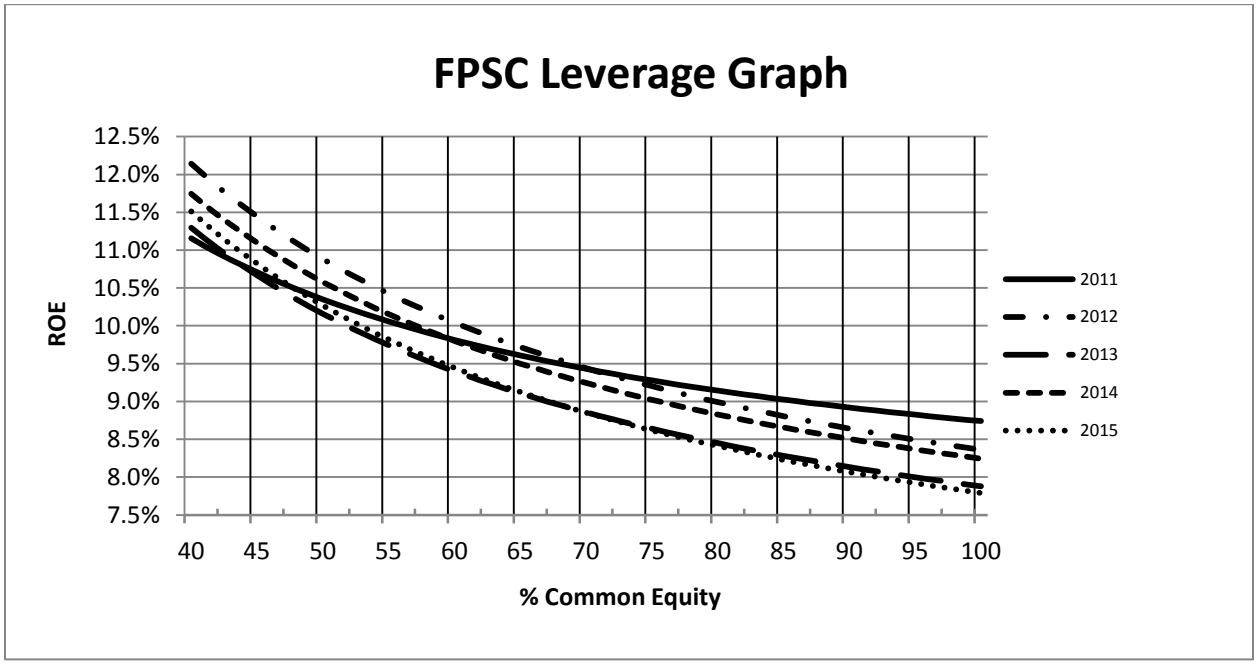


Chart 1-2 illustrates the change in the slope of the leverage formula for the five years 2011 through 2015.

Chart 1-2



In staff's opinion, the existing leverage formula range of 8.74 percent to 11.16 percent initially approved in 2011 is still reasonable for WAW utilities. Therefore, staff recommends that the current leverage formula approved in Docket No. 110006-WS continue to be used for determining the return on equity for WAW utilities in 2015. Staff believes retaining the use of the current leverage formula until the leverage formula is addressed again in 2016 is a reasonable alternative to updating the formula using current 2015 financial information.

Staff continues to believe the leverage formula is a sound, workable methodology that reduces the costs and administrative burdens in WAW rate cases by eliminating the need for cost of equity testimony. Many of the WAW utilities under the Commission's jurisdiction are small operations that find it beneficial to avoid the costs associated with presenting cost of equity testimony.

Although staff recommends the current 2011 leverage formula remain in place, staff has provided the updated leverage formula using the most recent financial information should the Commission decide to not continue to use the 2011 leverage formula and approve the updated leverage formula. The updated model produced the following leverage formula:

Return on Common Equity = 5.31% + (2.480 ÷ Equity Ratio)

Where the Equity Ratio = Common Equity ÷ (Common Equity + Preferred Equity + Long-Term + Short-Term Debt)

Range: 7.79% @ 100% equity to 11.51% @ 40% equity

In conjunction with the updated leverage formula, the returns on common equity should be capped at 11.51 percent for all WAW utilities with equity ratios less than 40 percent to discourage imprudent financial risk. This cap is consistent with the methodology in Order No. PSC-08-0846-FOF-WS.

In developing the updated leverage formula, staff used the same methodologies used in the 2011 docket. Staff notes that the leverage formula depends on four basic assumptions:

1) Business risk is similar for all WAW utilities;

2) The cost of equity is an exponential function of the equity ratio but a linear function of the debt to equity ratio over the relevant range;

3) The marginal weighted average cost of investor capital is constant over the equity ratio range of 40 percent to 100 percent; and

4) The debt cost rate at an assumed Moody's Baa3 bond rating, plus a 50 basis point private placement premium and a 50 basis point small utility risk premium, represents the average marginal cost of debt to a Florida WAW utility over an equity ratio range of 40 percent to 100 percent.

For these reasons, the leverage formula is assumed to be appropriate for the average Florida WAW utility.

The leverage formula relies on two ROE models. Staff adjusted the results of these models to reflect differences in risk and debt cost between the index of companies used in the models and the average Florida WAW utility. Both models include a four percent adjustment for flotation costs. The models are as follows:

- A Discounted Cash Flow (DCF) model applied to an index of natural gas utilities that have publicly traded stock and are followed by the Value Line Investment Survey (Value Line). This DCF model is an annual model and uses prospective growth rates.

- The index consists of eight natural gas companies that derive at least 50 percent of their total revenue from gas distribution service. These companies have a median Standard and Poor's bond rating of A-.

- A Capital Asset Pricing Model (CAPM) using a market return for companies followed by Value Line, the average yield on the Treasury's long-term bonds projected by the Blue Chip Financial Forecasts, and the average beta for the index of natural gas utilities. The market return for the 2015 leverage formula was calculated using a quarterly DCF model with stock prices as of May 15, 2015.

Staff averaged the indicated returns of the above models and adjusted the result as follows:

- A bond yield differential of 44 basis points is added to reflect the difference in yields between an A-/A3 rated bond, which is the median bond rating for the natural gas utility index, and a BBB-/Baa3 rated bond. Florida WAW utilities are assumed to be comparable to companies with the lowest investment grade bond rating, which is Baa3. This adjustment compensates for the difference between the credit quality of "A-" rated debt and the credit quality of the minimum investment grade rating.

- A private placement premium of 50 basis points is added to reflect the difference in yields on publicly traded debt and privately placed debt, which is illiquid. Investors require a premium for the lack of liquidity of privately placed debt.

- A small utility risk premium of 50 basis points is added because the average Florida WAW utility is too small to qualify for privately placed debt.

After the above adjustments, the resulting cost of equity estimate is included in the average capital structure for the natural gas utilities. The derivation of the leverage formula using the current methodology with updated financial information is presented in Attachment 1.

For administrative efficiency, the leverage formula is used to determine the appropriate return for an average Florida WAW utility. Traditionally, the Commission has applied the same leverage formula to all WAW utilities. As is the case with other regulated companies under the Commission's jurisdiction, the Commission has discretion in the determination of the appropriate ROE based on the evidentiary record in any proceeding. If one or more parties file testimony in opposition to the use of the leverage formula, the Commission will determine the appropriate ROE based on the evidentiary record in that proceeding.

Based on the aforementioned, staff believes that the current range of returns on common equity of 8.74 percent to 11.16 percent is still reasonable for WAW utilities. As such, staff recommends the current leverage formula authorized by the Commission in Order No. PSC-14-0272-PAA-WS remain unchanged until the leverage formula is readdressed in 2016.

Issue 2: Should this docket be closed?

Recommendation: No. Upon expiration of the protest period, if a timely protest is not received from a substantially affected person, the decision should become final and effective upon the issuance of a Consummating Order. However, this docket should remain open to allow staff to monitor changes in capital market conditions and to readdress the reasonableness of the leverage formula as conditions warrant. (Janjic, Mapp)

Staff Analysis: Upon expiration of the protest period, if a timely protest is not received from a substantially affected person, the decision should become final and effective upon the issuance of a Consummating Order. However, this docket should remain open to allow staff to monitor changes in capital market conditions and to readdress the reasonableness of the leverage formula as conditions warrant.

SUMMARY OF LEVERAGE FORMULA RESULTS

	Updated Results (2015)	Currently in Effect (2011)
(A) DCF ROE for Natural Gas Utility Index	8.40%	8.25%
(B) CAPM ROE for Natural Gas Utility Index	10.12%	9.40%
AVERAGE	9.29%	8.83%
Bond Yield Differential	0.44%	0.57%
Private Placement Premium	0.50%	0.50%
Small-Utility Risk Premium	0.50%	0.50%
Adjustment to Reflect ROE at 40% Equity Ratio	0.81%	0.76%
Cost of Equity for Average Florida WAW Utility with a capital structure containing a 40% Equity Ratio	11.51%	11.16%

2011 Leverage Formula (Currently in Effect)

Return on Common Equity = 7.13% + (1.610 ÷ Equity Ratio)
Range of Returns on Equity (100% to 40%) = 8.74% to 11.16%

2015 Leverage Formula (Using Current Data)

Return on Common Equity = 5.31% + (2.480 ÷ Equity Ratio)
Range of Returns on Equity (100% to 40%) = 7.79% to 11.51%

MARGINAL COST OF INVESTOR CAPITAL
(2015 Leverage Formula Result)

Average Marginal Cost Rate of the Natural Gas Utility Index

Capital Component	Ratio	Marginal Cost Rate	Weighted Marginal Cost Rate
Common Equity	45.95%	10.70%	4.92%
Total Debt	54.05%	5.31% *	2.87%
	100.0%		7.79%

Average Marginal Cost Rate at a 40% Equity Ratio

A 40% equity ratio is the floor for calculating the required return on common equity. The return on equity at a 40% equity ratio is 5.31% + (2.480 ÷ 0.40) = 11.51%

Capital Component	Ratio	Marginal Cost Rate	Weighted Marginal Cost Rate
Common Equity	40.00%	11.51%	4.60%
Total Debt	60.00%	5.31%*	3.18%
	100.00%		7.79%

Common Equity Ratio = Common Equity ÷ (Common Equity + Preferred Equity + Long-Term Debt + Short-Term Debt)

*Assumed 120-month average Baa3 rate as of April 2015 (4.31%) plus a 50 basis point private placement premium and a 50 basis point small utility risk premium.

Sources: Moody's Credit Perspectives and Value Line Selection and Opinion

ANNUAL DISCOUNTED CASH FLOW MODEL

NATURAL GAS UTILITY INDEX

COMPANY	DIV0	DIV1	DIV2	DIV3	DIV4	EPS4	ROE4	GR1-4	GR4+	STOCK PRICE APRIL 1, 2015 - APRIL 30, 2015 HI-PR	LO-PR	AVG-PR
AGL RESOURCES INC.	2.04	2.10	2.20	2.30	2.40	4.65	11.50	1.0455	1.0556	51.88	49.14	50.510
ATMOS ENERGY CORPORATION	1.56	1.64	1.72	1.81	1.90	3.80	10.50	1.0503	1.0525	56.67	53.67	55.170
LACLEDE GROUP, INC.	1.84	1.92	2.01	2.10	2.20	4.20	8.50	1.0464	1.0405	52.95	50.82	51.885
NORTHWEST NATURAL GAS CO.	1.87	1.91	1.97	2.03	2.10	3.30	9.00	1.0321	1.0327	49.77	46.54	48.155
PIEDMONT NATURAL GAS CO., INC.	1.31	1.35	1.39	1.43	1.47	2.10	10.50	1.0288	1.0315	38.43	36.17	37.300
SOUTH JERSEY INDUSTRIES, INC.	2.05	2.20	2.34	2.49	2.65	5.00	14.50	1.0640	1.0682	55.32	52.40	53.860
SOUTHWEST GAS CORPORATION	1.62	1.74	1.85	1.97	2.10	4.25	12.00	1.0647	1.0607	59.75	54.46	57.105
WGL HOLDINGS, INC.	1.85	1.87	1.87	1.87	1.87	3.20	11.00	1.0000	1.0457	57.94	54.79	56.365
AVERAGE	1.7675	1.8413	1.9188	2.0004	2.0863	3.8125	10.9375	1.0415	1.0484			51.294
					2.1873		Stock price including a four percent flotation cost:					**49.242**
		Annual DCF Result:		**8.40%**								

Cash Flows	1.6476	1.5835	1.5226	1.4645	1.4109	41.6130
Present Value of Cash Flows	49.2420					

NOTE: The cash flows for this multi-stage DCF Model are derived using the average forecasted dividends and the near term and long term growth rates. The discount rate equates the cash flows with the average stock price less flotation cost.
$49.242 = Average stock price from April 1, 2015, through April 30, 2015, with a 4 percent flotation cost.
8.40% = Cost of equity required to match the current stock price with the expected cash flows.
Sources:
1. Stock Prices - Yahoo Finance.
2. Dividends (DIV), Dividends Per Share (DPS), Earnings Per Share (EPS), ROE - Value Line Ratings and Reports issued March 7, 2015.

CAPITAL ASSET PRICING MODEL

CAPM Analysis Formula

K = RF + Beta(MR - RF)

K = Investor's required rate of return

RF = Risk-free rate (Blue Chip forecast for Long-term Treasury bond, May 1, 2015)

Beta = Measure of industry-specific risk (Average for natural gas utilities followed by Value Line)

MR = Market return (Value Line Investment Analyzer Web Browser, as of May 15, 2015)

10.12% = 3.30% + 0.794(11.64% - 3.30%) + 0.20%

Note: Staff calculated the market return using a quarterly DCF model for a large number of dividend paying stocks followed by Value Line. As of May 15, 2015, the result was 11.64%. Staff also added 20 basis points to the CAPM result to allow for a four-percent flotation cost.

BOND YIELD DIFFERENTIALS

Public Utility Long Term Bond Yield Averages									
Month, Year	A2	Spread	A3	Spread	Baa1	Spread	Baa2	Spread	**Baa3**
April, 2015	3.788	0.123	3.911	0.123	4.034	0.123	4.158	0.123	4.281
120-Month Average							4.158	0.1479	**4.31%**
Sources: Moody's Credit Perspectives and Value Line Selection & Opinion									

UTILITY INDEX STATISTICS AND FACTS

Natural Gas Distribution Utility Companies	S&P Bond Rating	% of Gas Revenue	Value Line Market Capital (millions)	Equity Ratio	Value Line Beta
AGL Resources Inc.	BBB+	69%	$ 5,995.51	43.19%	0.80
Atmos Energy Corporation	A-	64%	$ 5,549.99	53.78%	0.85
Laclede Group, Inc.	A-	99%	$ 2,231.98	41.37%	0.70
Northwest Natural Gas Co.	A+	97%	$ 1,298.67	45.69%	0.70
Piedmont Natural Gas Co., Inc.	A	100%	$ 2,914.38	42.38%	0.80
South Jersey Industries, Inc.	BBB+	57%	$ 1,762.88	42.64%	0.85
Southwest Gas Corporation	BBB+	63%	$ 2,674.78	47.21%	0.85
WGL Holdings, Inc.	A+	50%	$ 2,776.69	51.35%	0.80
Average:	A-	75%	$ 3,150.61	45.95%	0.794

Sources:
Value Line Investment Analyzer Web Browser, April 2015
S.E.C. Forms 10Q and 10K for the natural gas utility companies
AUS Utilities Report, issued May 1, 2015
Standard & Poor's RatingsDirect

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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Engineering (P. Buys, King)
Division of Accounting and Finance (T. Brown, Norris)
Division of Economics (Bruce, Hudson)
Office of the General Counsel (Villafrate)

RE: Docket No. 150019-WS – Joint application of GCP REIT III and Sun Communities Operating Limited Partnership for authority for transfer of majority organizational control of GCP Plantation Landings, LLC.

AGENDA: 06/18/15 – Regular Agenda – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brisé

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

GCP Plantation Landings, LLC, (Plantation Landings) is a Class C water and wastewater Utility serving approximately 419 customers in Polk County. According to Plantation Landings' 2013 Annual Report, total gross revenues were $123,192.

Prior to 1998, water and wastewater services had been provided to Plantation Landings Mobile Home Park since 1987 under the provisions of Chapter 723, Florida Statutes (F.S.), which governs mobile home park lot tenancies. In 1998, Plantation Landings applied for a grandfather certificate and obtained Certificate Nos. 606-W and 522-S from the Commission in

1999.[1] The Commission established rate base for Plantation Landings by Order No PSC-08-0548-PAA-WS, issued August 19, 2008.[2] On March 11, 2013, the Commission approved the transfer of Plantation Landings' water and wastewater systems and Certificate Nos. 606-W and 522-S to GCP Plantation Landings, LLC.[3]

On January 6, 2015, a joint application for authority for transfer of majority organizational control was filed by GCP REIT III and Sun Communities Operating Limited Partnership. The application as filed did not have any deficiencies. The Commission has jurisdiction in this case pursuant to Section 367.071, F.S.

[1] Order No. PSC-99-1227-PAA-WS, issued June 21, 1999, in Docket No. 981338-WS, In re: Application for grandfather certificate to operate water and wastewater utility in Polk County by Plantation Landings, Ltd.
[2] Order No. PSC-08-0548-PAA-WS, issued August 19, 2008, in Docket No. 070416-WS, In re: Application for staff-assisted rate case in Polk County by Plantation Landings, Ltd.
[3] Order No. PSC-13-0121-PAA-WS, issued March 11, 2013, in Docket No. 120219-WS, In re: Application for approval of transfer of Plantation Landings, Ltd. water and wastewater system and Certificate Nos. 606-W and 522-S in Polk County to GCP Plantation Landings, LLC.

Discussion of Issues

Issue 1: Should the application for transfer of majority organizational control of GCP Plantation Landings, LLC, in Polk County to Sun Communities Operating Limited Partnership be approved?

Recommendation: Yes. The transfer of majority organizational control to Sun Communities Operating Limited Partnership (Sun Communities OLP) is in the public interest and should be approved effective the date of the Commission vote. The resultant order should serve as the water and wastewater certificates, with the territory described in Attachment A. 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.). (P. Buys, T. Brown, Bruce)

Staff Analysis: This application is for the transfer of majority organizational control of GCP Plantation Landings, LLC, to Sun Communities Operating Limited Partnership. Based on staff's review, the application is in compliance with the governing statue, Section 367.071, F.S., and Rule 25-30.037(3), F.A.C., concerning applications for transfer of majority organizational control.

Noticing, Territory, and Ownership

The applicant provided 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 with the Commission, and the time for doing so has expired. The notice contains a description of the territory for Plantation Landings, which is appended to this recommendation as Attachment A. The application does not involve transfer of the facilities and Plantation Landings will continue to lease the land where the water and wastewater treatment plants are currently located. The evidence of the lease has previously been provided to the Commission.[4]

Technical and Financial Ability

Pursuant to Rule 25-30.037(3)(f), F.A.C., the application contains statements describing the technical and financial ability of the applicant to provide service to the proposed service area. Staff has reviewed the consolidated balance sheet of Sun Communities, Inc., (parent company of Sun Communities OLP) and the attestation in the transfer application asserting that Sun Communities, Inc., has the financial ability required to fund future capital expenditures on an "as needed" basis.[5] Based on its review, staff believes the documents show that Sun Communities OLP has the financial capability to operate the water and wastewater systems. According to the application, there will be no immediate change in the day-to-day operational management of the systems. Sun Communities OLP is currently engaged in water and wastewater utility service

[4] Order No. PSC-13-0121-PAA-WS, issued March 11, 2013, in Docket No. 120219-WS, In re: Application for approval of transfer of Plantation Landings, Ltd. water and wastewater system and Certificate Nos. 606-W and 522-S in Polk County to GCP Plantation Landings, LLC.
[5] Document No. 00112-15, in Docket No. 150019-WS.

operations in Florida through its ownership of the Saddle Oak Club system in Marion County, Buttonwood Bay in Highlands County, and Water Oak in Lake County which are regulated by the Commission. In addition, Sun Communities, Inc., also operates approximately seven systems that are either unregulated, or regulated by county governments. Staff believes that the water and wastewater systems appear to be in satisfactory condition and are in compliance with Florida Department of Environmental Protection. Based on the above, it appears that Plantation Landings and Sun Communities OLP have demonstrated the technical and financial ability to provide service to the existing service territory

Rates and Charges

The Utility's rates were last approved in a staff-assisted rate case in 2008.[6] The rates were subsequently reduced to reflect the four-year rate reduction required by Section 367.0816, F.S., in 2013. Staff notes that the Utility does not have customer deposits, miscellaneous service or service availability charges. The Utility's existing rates are shown on Schedule No. 1. 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.

Conclusion

Based on the above, staff recommends that the transfer of majority organizational control to Sun Communities Operating Limited Partnership is in the public interest and should be approved effective the date of the Commission vote. The resultant order should serve as the water and wastewater certificates, with the territory described in Attachment A. The existing rates and charges should remain in effect until a change is authorized by the Commission in a subsequent proceeding. The tariffs reflecting the transfer should be effective for services rendered or connections made on or after the stamped approval date on the tariffs, pursuant to Rule 25-30.475, F.A.C.

[6] Order No. PSC-08-0548-PAA-WS, issued August 19, 2008, in Docket No. 070416-WS, In re: Application for staff-assisted rate case in Polk County by Plantation Landings, Ltd.

Issue 2: Should this docket be closed?

Recommendation: Yes. If the Commission approves staff's recommendation in Issue 1, this docket should be closed. (Villafrate)

Staff Analysis: If the Commission approves staff's recommendation in Issue 1, this docket should be closed.

GCP Plantation Landings, LLC

Polk County

Description of Water and Wastewater Territory

In Part of Section 25, Township 27 South, Range 26 East, and Section 31, Township 27 South, Range 27 East, Polk County, Florida described as follows:

Section 25, Township 27 South, Range 26 East

Commence at the Southwest corner of the Southeast 1/4 of the Southwest 1/4 of the Northeast 1/4, thence run North 89°50'54" East a distance of 366.37 feet to the Point of Beginning; thence run North 00°07'52" West a distance of 70.32 feet; thence run South 79°37'37" East along the southerly boundary line of U.S. 17-92 (State Road 600) to the intersection of said line with the North boundary line of said South 1/2 of Section 25; thence run South 89°50'54" West to the Point of Beginning; and

That part of the East 3/4 of the South 1/2 of Section 25, Township 27 South, Range 26 East which lies south of U.S. 17-92 (State Road 600) LESS AND EXCEPT the following tracts of land:

A. The North 208.71 feet of the Easterly 869.6 feet of the Northeast 1/4 of the Southwest 1/4 of Section 25.

B. That certain parcel of land described as follows: commence at the center of Section 25, Township 27 South, Range 26 East; thence run South 00°12'09" East along the quarter line a distance of 138.44 feet; thence run South 79°38'00" East a distance of 674.55 feet; thence run North 00°10'00" West a distance of 261.60 feet; thence run westerly along the North boundary line of the S 1/2 of said Section 25 to the Point of Beginning.

C. The East 1/4 of the Northeast 1/4 of the Southeast 1/4 and West 1/2 of the Northeast 1/4 of the Northeast 1/4 of the Southeast 1/4 of said Section 25.

D. The South 600 feet of the North 612.93 feet of the West 200 feet of the East 240 feet of the Southeast 1/4 of the Southeast 1/4 of Section 25.

Section 31, Township 27 South, Range 27 East Plantation Landings (percolation pond)

Commence at the Northwest corner of Section 31, Township 27 South, Range 27 East, Polk County, Florida run South 00°00'54" West, along the West boundary of said Section 31, a distance of 30.0 feet to the Point of Beginning; thence run North 89°38'18" East a distance of 558.0 feet; thence run South 00°16'22" West, a distance of 37.81 feet; thence run South 86°35'00" East, a distance of 688.0 feet; thence run South 03°00'00" East, a distance of 295.0 feet; thence run North 83°07'00" West, a distance of 925.0 feet; thence run North 04°25'00" East, a distance of 237.0 feet; thence run South 89°38'18" West, a distance of 360.0 feet to a point in the West boundary of said Section 31; thence run North 00°03'54" East, a distance of 25.0 feet to the Point of Beginning. LESS AND EXCEPT the West 25.0 feet, thereof, for road Right-of-Way of Dyson Road.

FLORIDA PUBLIC SERVICE COMMISSION

Authorizes

GCP Plantation Landings, LLC

pursuant to

Certificate Number 606-W

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

Order Number	Date Issued	Docket Number	Filing Type
PSC-99-1227-PAA-WS	06/21/99	981338-WS	Grandfather Certificate
PSC-13-0121-PAA-WS	03/11/13	120219-WS	Transfer of Certificate
*	*	150019-WS	Transfer of Majority Organizational Control

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

FLORIDA PUBLIC SERVICE COMMISSION

Authorizes

GCP Plantation Landings, LLC

pursuant to

Certificate Number 522-S

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

Order Number	Date Issued	Docket Number	Filing Type
PSC-99-1227-PAA-WS	06/21/99	981338-WS	Grandfather Certificate
PSC-13-0121-PAA-WS	03/11/13	120219-WS	Transfer of Certificate
*	*	150019-WS	Transfer of Majority Organizational Control

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

GCP Plantation Landings, LLC
Monthly Water Rates

Residential and General Service

Base Facility Charge by Meter Size	
5/8" x 3/4"	$4.71
3/4"	$7.07
1"	$11.78
1 1/2"	$23.55
2"	$37.68
3"	$75.37
4"	$117.76
6"	$235.52
Charge Per 1,000 gallons	$1.62

Monthly Wastewater Rates

Residential Service

Base Facility Charge – All Meter Sizes	$9.41
Charge Per 1,000 gallons 6,000 gallon cap	$2.67

General Service

Base Facility Charge by Meter Size	
5/8" x 3/4"	$9.41
3/4"	$14.11
1"	$23.52
1 1/2"	$47.05
2"	$75.27
3"	$150.55
4"	$235.23
6"	$470.47
Charge Per 1,000 gallons	$3.22

Item 7

State of Florida

Public Service Commission

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

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

DATE: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Ollila) A.O. EJO
Office of the General Counsel (Brownless) MW JSC

RE: Docket No. 150103-EI – Petition for approval of revised underground residential distribution tariff, by Tampa Electric Company.

AGENDA: 06/18/15 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 60-Day Suspension Date Waived by the Company Until the 6/18/15 Agenda Conference

SPECIAL INSTRUCTIONS: None

Case Background

On April 1, 2015, Tampa Electric Company (TECO) filed a petition for approval of its revised underground residential distribution (URD) tariff. These tariffs reflect the additional costs the customer must pay for initial service above the standard overhead service. The proposed tariffs are shown in Attachment 1. TECO's current charges were approved in Order No. PSC-12-0499-TRF-EI (2012 Order).[1] Staff issued one data request to TECO. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes.

[1] Order No. PSC-12-0499-TRF-EI, issued September 27, 2012, in Docket No. 120073-EI, In re: Petition for approval of revised tariffs for underground residential distribution and contribution-in-aid-construction, by Tampa Electric Company.

Discussion of Issues

Issue 1: Should the Commission approve TECO's proposed URD tariffs and associated charges?

Recommendation: Yes, the Commission should approve TECO's proposed URD tariffs and associated charges effective June 18, 2015. (Ollila)

Staff Analysis: Rule 25-6.078, Florida Administrative Code (F.A.C.), defines investor-owned utilities' (IOU) responsibilities for filing updated URD tariffs. IOUs are required to file supporting data and analyses for URD tariffs at least once every three years. The URD tariffs provide standard charges for underground service in new residential subdivisions and represent the additional costs the utility incurs to provide underground service in place of standard overhead service. The cost of standard overhead construction is recovered through base rates from all ratepayers. In lieu of overhead construction, customers have the option of requesting underground facilities. Costs for underground construction have historically been higher than for standard overhead construction and the additional cost is paid by the customers as contribution-in-aid-of construction (CIAC). Typically the URD customer is the developer of the subdivision.

TECO's URD charges are based on two standard model subdivisions: (1) a 210-lot low density (LD) subdivision, and (2) a 176-lot high density (HD) subdivision. While actual construction may differ, the model subdivisions are designed to reflect average subdivisions. The design of the HD subdivision is the same as in 2012; however, TECO stated that it made modifications to the LD subdivision design to increase reliability. Specifically, TECO added transformers and adjusted the length of primary cable and service laterals.

Table 1-1 displays the currently approved and proposed URD differentials for the LD and HD subdivisions. The charges shown are per-lot charges.

Table 1-1
Comparison of URD Differential Per Lot

	Current Differential Per Lot	Proposed Differential Per Lot
210-Lot Low Density	$440.31	$373.86[2]
176-Lot High Density	$103.95	$47.64

As shown in the table above, the differentials per-lot have decreased for both subdivisions. The calculation of TECO's proposed URD charges are based on 1) updated labor and material costs, and 2) calculation of operational costs.

Updated labor and material costs. The installation costs of both underground and overhead facilities include the material and labor costs to provide primary, secondary, and service distribution lines as well as transformers. The costs of poles are specific to overhead service while the costs of trenching and backfilling are specific to underground service. The

[2] $374 is calculated as follows: $858 (Table 1-2) + ($484) (Table 1-3) = $374.

current URD charges are based on 2012 labor and material costs, and the proposed charges are based on 2015 costs. Table 1-2 compares the per-lot 2012 and 2015 underground and overhead labor and material costs for the two subdivisions.

Table 1-2
Labor and Material Costs per Lot*

	2012 Costs	2015 Costs	Difference
Low Density			
Underground labor/material costs	$2,049	$2,127	$78
Overhead labor/material costs	$1,205	$1,269	$64
Per lot differential	$844	$858	$14
High Density			
Underground labor/material costs	$1,619	$1,638	$19
Overhead labor/material costs	$947	$979	$32
Per lot differential	$672	$659	-$12

*Numbers are rounded to whole dollars.

As indicated in the table above, the changes in total labor and material cost differentials are minimal for the two model subdivisions. Documentation provided by TECO indicates some labor and material costs such as for secondary lines and transformers increased, while other costs decreased, resulting in a minimal net-effect.

Calculation of operational costs. Rule 25-6.078(4), F.A.C., provides that the differences in Net Present Value (NPV) of operational costs between overhead and underground systems, including average historical storm restoration costs over the life of the facilities, be included in the URD charge. Operational costs include operations and maintenance (O&M) costs and capital costs. The inclusion of the operational costs are intended to capture longer term costs and benefits of undergrounding. TECO used its actual historical O&M and capital expenses for the period 2012 through 2014 to calculate the operational difference for overhead and underground facilities.

Table 1-3 below compares the 2012 and 2015 NPV calculations of operational cost differentials between overhead and underground systems on a per-lot basis.

Table 1-3
NPV of Operational Costs Differential per Lot*

	2012 Calculation	2015 Calculation	Difference
Low Density			
Underground	$988	$906	-$82
Overhead	$1,392	$1,390	-$2
Per lot differential	-$404	-$484	-$80
High Density			
Underground	$483	$432	-$52
Overhead	$1,051	$1,044	-$7
Per lot differential	-$568	-$612	-$44

*Numbers are rounded to whole dollars.

TECO used the same methodology as approved in Order No. PSC-09-0784-TRF-EI for calculating the NPV of operational costs.[3] TECO's NPV calculation used a 35-year life of the facilities and a 7.29 percent discount rate. Staff notes that operational costs may vary among IOUs as result of differences in size of service territory, miles of coastline, regions subject to extreme winds, age of the distribution system, or construction standards.

Conclusion. In summary, for LD subdivision lots, the proposed labor and material differential is a $14 increase from current costs. The operational cost savings not only offset the $14 increase, but serve to reduce the proposed differential an additional $66 from the current differential. For the HD subdivision lots, the proposed labor and material differential is a $12 decrease from the current differential. The operational cost savings add an additional decrease of $44 from the current differential, for a total decrease of $56 from the current differential.

Staff has reviewed TECO's proposed URD charges and associated tariffs, its accompanying work papers, and data request response. Staff believes the proposed URD tariffs and associated charges are reasonable and recommends approval, effective June 18, 2015.

[3] Order No. PSC-09-0784-TRF-EI, issued November 19, 2009, in Docket No. 090164-EI, In re: Petition for approval of revised tariff sheets for underground residential distribution service, by Tampa Electric Company.

Issue 2: Should this docket be closed?

no. MM 6.4.15

Recommendation: ~~Yes.~~ If a protest is filed within 21 days of the issuance of the order, this 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. (Brownless)

Staff Analysis: If a protest is filed within 21 days of the issuance of the order, this 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.

TAMPA ELECTRIC

EIGHTH REVISED SHEET NO. 5.510
CANCELS SEVENTH REVISED SHEET NO. 5.510

Continued from Sheet No. 5.500

3.6.5.1 **Single Meter Commercial Service**
Mobile Home Parks will be supplied single-meter commercial service only where park owner or operator supplies (furnishes) electrical service as a part of his rental and/or general service charge to tenants. Resale of electric energy through park owned meters will not be permitted (See 2.2.1)

3.6.5.2 **Individual Company Metered Service**
Mobile Home Parks will be supplied through company installed individual meters for individual tenants and other types of service required in park under the provisions required on 3.4.3 and 3.4.4 and the subparts appertaining thereto.

3.6.6 **Miscellaneous Types of Electric Service**
Certain other types of electric service are available from the company. Information on such services not specifically covered in this Tariff may be obtained at the nearest company office. Such special cases will be given individual consideration.

3.7 **SCHEDULE OF STANDARD CHARGES AND NON-REFUNDABLE DEPOSITS FOR COST ESTIMATES FOR UNDERGROUND ELECTRIC DISTRIBUTION SYSTEMS**

3.7.1 **Standard Charges**
The Standard Charges listed here are Contributions In Aid of Construction (CIAC) which are referenced by other sections of these rules and regulations.

3.7.1.1 **Residential Subdivision**

Low Density Subdivisions per service lateral or dwelling unit...	$373.86
High Density Subdivisions per service lateral or dwelling unit...	$47.64

3.7.1.2 **New Single-phase UG Service Laterals from Overhead Distribution Systems**

Fixed Charge for 2/0 service lateral	$56.58
Fixed Charge for 4/0 service lateral	$95.75
Per trench foot charge for 2/0 service lateral	$9.94
Per trench foot charge for 4/0 service lateral	$10.27
Credit for service pole if otherwise required for overhead service	$534.28

Continued to Sheet No. 5.515

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

TAMPA ELECTRIC

FOURTEENTH REVISED SHEET NO. 5.515
CANCELS THIRTEENTH REVISED SHEET NO. 5.515

Continued from Sheet No. 5.510

3.7.1.3 **Single-phase UG Service Laterals Converted from Existing Overhead Service Drops**

Removal charge for overhead service with no service pole	$111.45
Removal charge for overhead service with a service pole	$508.66
Fixed Charge for 2/0 service lateral	$56.58
Fixed Charge for 4/0 service lateral	$95.75
Per trench foot charge for 2/0 service lateral	$9.94
Per trench foot charge for 4/0 service lateral	$10.27
Credit for service pole if otherwise required for overhead service	$534.28

Continued to Sheet No. 5.516

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

TAMPA ELECTRIC

EIGHTH REVISED SHEET NO. 5.516
CANCELS SEVENTH REVISED SHEET NO. 5.516

Continued from Sheet No. 5.515

3.7.2 Non-refundable Deposits for Estimates of CIAC for Conversion of Existing Overhead Distribution Facilities to Underground Facilities

Qualified applicants can request, upon payment of a non-refundable deposit as listed below, the conversion of overhead distribution facilities to underground in accordance with these Rules and Regulations for conversion areas of not less than one (1) city block in length along both sides of the main distribution system, or in the absence of city blocks, not less than five (5) contiguous building lots along both sides of the main distribution system, or in the absence of both, not the less than 600 pole-feet of the main distribution system, including all customers served along both sides of the main distribution system, and so as to result in a decrease in the number of non-lighting poles in the system.

Requests for conversions, except for individual residential service covered under Section 3.4.3.3, will be accompanied by a non-refundable amount as follows:

Density Class	Deposit Amount
Urban Commercial or Residential.....	$9,346 per mile*
Rural Commercial or Residential.....	$5,466 per mile*
High or Low Density Subdivision.....	$ 45 per lot

* As measured along the existing overhead primary and secondary distribution system.

ISSUED BY: G. L. Gillette, President

DATE EFFECTIVE:

Item 8

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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Ollila)
Office of the General Counsel (Brownless)

RE: Docket No. 150112-EI – Request by Gulf Power Company to modify its underground residential differential tariffs.

AGENDA: 06/18/15 – Regular Agenda – Tariff Filing – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: 12/01/15 (8-Month Effective Date)

SPECIAL INSTRUCTIONS: None

Case Background

On April 1, 2015, Gulf Power Company (Gulf) filed its revised underground residential distribution (URD) tariff. These tariffs reflect the additional costs the customer must pay for initial service above the standard overhead service. The proposed tariffs are shown in Attachment 1. Gulf's current charges were approved in Order No. PSC-12-0531-TRF-EI (2012 Order).[1] On April 13, 2015, Gulf waived the 60-day suspension date. Staff issued two data requests to Gulf. The Commission has jurisdiction over this matter pursuant to Sections 366.03, 366.04, 366.05, and 366.06, Florida Statutes.

[1] Order No. PSC-12-0531-TRF-EI, issued October 4, 2012, in Docket No. 120075-EI, In re: Request by Gulf Power Company to modify its underground residential differential tariffs.

Discussion of Issues

Issue 1: Should the Commission approve Gulf's proposed URD tariffs and associated charges?

Recommendation: Yes, the Commission should approve Gulf's proposed URD tariffs and associated charges effective June 18, 2015. (Ollila)

Staff Analysis: Rule 25-6.078, Florida Administrative Code (F.A.C.), defines investor-owned utilities' (IOUs) responsibilities for filing updated URD tariffs. IOUs are required to file supporting data and analyses for URD tariffs at least once every three years. The URD tariffs provide standard charges for underground service in new residential subdivisions and represent the additional costs the utility incurs to provide underground service in place of standard overhead service. The cost of standard overhead construction is recovered through base rates from all ratepayers. In lieu of overhead construction, customers have the option of requesting underground facilities. Costs for underground construction have historically been higher than for standard overhead construction and the additional cost is paid by the customers as contribution-in-aid-of construction (CIAC). Typically the URD customer is the developer of the subdivision.

Gulf's URD charges are based on two standard model subdivisions: (1) a 210-lot low density (LD) subdivision, and (2) a 176-lot high density (HD) subdivision. While actual construction may differ, the model subdivisions are designed to reflect average subdivisions. Gulf explained that both subdivision underground designs were updated to reflect changes in construction standards, resulting in minor increases to the affected materials.

Table 1-1 displays the currently approved and proposed URD differentials for the LD and HD subdivisions. The charges shown are per-lot charges. Gulf's URD tariff also provides for reduced charges if the customer chooses to supply and/or install the primary and secondary trench and duct system.

Table 1-1
Comparison of URD Differential Per Lot

	Current Differential Per Lot	Proposed Differential Per Lot
210-Lot Low Density	$427	$402[2]
176-Lot High Density	$458	$521

As shown in the table above, the differential per-lot has decreased for the LD subdivision and increased for the HD subdivision. The calculation of Gulf's proposed URD charges are based on 1) updated labor and material costs, and 2) calculation of operational costs.

Updated labor and material costs. The installation costs of both underground and overhead facilities include the material and labor costs to provide primary, secondary, and service distribution lines as well as transformers. The costs of poles are specific to overhead

[2] $402 is calculated as follows: $592 (Table 1-2) + ($190) (Table 1-3) = $402.

service while the costs of trenching and backfilling are specific to underground service. The current URD charges are based on 2012 labor and material costs, and the proposed charges are based on 2015 costs. Table 1-2 compares the per-lot 2012 and 2015 underground and overhead labor and material costs for the two subdivisions.

Table 1-2
Labor and Material Costs per Lot

	2012 Costs	2015 Costs	Difference
Low Density			
Underground labor/material costs	$2,258	$2,307	$49
Overhead labor/material costs	$1,701	$1,715	$14
Per lot differential	$557	$592	$35
High Density			
Underground labor/material costs	$1,803	$1,895	$92
Overhead labor/material costs	$1,325	$1,331	$6
Per lot differential	$478	$564	$86

As indicated in the table above, the changes in total labor and material cost differentials are minimal for the two model subdivisions. Gulf stated that the overall increases in LD and HD underground labor and material costs result from increases in the cost of contract labor (used for trenching and the installation of duct work) and are somewhat mitigated by decreases in material costs. Specifically, the decrease in material costs is driven by the volume procurement of transformers. The increase in overhead costs is minimal.

Calculation of operational costs. Rule 25-6.078(4), F.A.C., provides that the differences in Net Present Value (NPV) of operational costs between overhead and underground systems, including average historical storm restoration costs over the life of the facilities, be included in the URD charge. Operational costs include operations and maintenance (O&M) costs and capital costs. The inclusion of the operational costs are intended to capture longer term costs and benefits of undergrounding. Gulf used its actual historical O&M and capital expenses for the period 2010 through 2014 to calculate the operational difference for overhead and underground facilities.

Table 1-3 below compares the 2012 and 2015 NPV calculations of operational cost differentials between overhead and underground systems on a per-lot basis.

Table 1-3
NPV of Operational Costs per Lot

	2012 Calculation	2015 Calculation	Difference
Low Density			
Underground	$379	$436	$57
Overhead	$509	$626	$117
Per lot differential	-$130	-$190	-$60
High Density			
Underground	$238	$274	$36
Overhead	$258	$317	$59
Per lot differential	-$20	-$43	-$23

Gulf used the same methodology as updated in the 2012 Order and originally approved in Order No. PSC-10-0563-TRF-EI.[3] Gulf's NPV calculation used a 32-year life of the facilities and a 6.72 percent discount rate. Staff notes that operational costs may vary among IOUs as a result of differences in size of service territory, miles of coastline, regions subject to extreme winds, age of the distribution system, or construction standards.

Conclusion. In summary, for LD subdivision lots, the proposed labor and material differential is a $35 increase from current costs. The operational cost savings not only offset the $35 increase, but serve to reduce the proposed differential an additional $25 from the current differential. For the HD subdivision lots, the proposed labor and material differential is an $86 increase from the current differential. The operational cost savings reflect a decrease of $23 from the current differential, for a total increase of $63 from the current differential.

Staff has reviewed Gulf's proposed URD charges and associated tariffs, its accompanying work papers, and data request responses. Staff believes the proposed URD charges are reasonable and recommends approval, effective June 18, 2015.

[3] Order No. PSC-10-0563-TRF-EI, issued September 14, 2012, in Docket No. 100165-EI, In re: Request to revise 2010 overhead/underground residential differential cost data by Gulf Power Company.

Issue 2: Should this docket be closed?

Recommendation: ~~Yes.~~ no. If a protest is filed within 21 days of the issuance of the order, this 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. (Brownless) 6.4.15

Staff Analysis: If a protest is filed within 21 days of the issuance of the order, this 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.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
Thirteenth Revised Sheet No. 4.25
Canceling Twelfth Revised Sheet No. 4.25

PAGE	EFFECTIVE DATE

6.2.8 DAMAGE TO COMPANY'S EQUIPMENT. The Applicant shall be responsible to ensure that the Company's distribution facilities once installed, are not damaged, destroyed, or otherwise disturbed during the construction of the project. This responsibility shall extend not only to those in his employ, but also to his subcontractors. Should damage occur, the Applicant shall be responsible for the full cost of repairs.

6.2.9 PAYMENT OF CHARGES. The Company shall not be obligated to install any facilities until payment of applicable charges, if any, has been completed.

6.3 UNDERGROUND DISTRIBUTION FACILITIES FOR NEW RESIDENTIAL SUBDIVISIONS

6.3.1 AVAILABILITY. After receipt of proper application and compliance by the Applicant with applicable Company rules and procedures, the Company will install underground distribution facilities to provide single phase service to new residential subdivisions of five (5) or more building lots.

6.3.2 CONTRIBUTION BY APPLICANT.

(a) Prior to such installations, the Applicant and the Company will enter into an agreement outlining the terms and conditions of installation, and the Applicant will be required to pay the Company in advance the entire cost as described below:

Option	Low Density Subdivision ($ per lot)	High Density Subdivision ($ per lot)
1. Gulf supplies and installs all primary, secondary, and service trench, duct, and cable.	$402	$521
2. Applicant installs primary and secondary trench and duct system. Gulf supplies primary and secondary duct and supplies and installs service duct. Gulf supplies and installs primary, secondary, and service cable.	$209	$384
3. Applicant supplies and installs primary and secondary trench and duct. Gulf supplies primary and secondary cable. Gulf supplies and installs service duct and cable.	$90	$289

All construction done by the Applicant must meet the Company's specifications. All installations must be approved by the Company's authorized representative.

(b) The Applicant is required to pay a charge per foot and a cost differential for transformers and services (see "Three Phase Lift Station" charts below) for three phase commercial loads requiring 120/240 volt open delta, 120/208 volt wye, or 277/480 volt wye service in new residential subdivisions for each three phase service. This average cost will be added to the advanced payment in 6.3.2(a) above.

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
Seventeenth Revised Sheet No. 4.26
Canceling Sixteenth Revised Sheet No. 4.26

PAGE	EFFECTIVE DATE

6.3.2 (continued)

THREE PHASE LIFT STATION
COSTS TO PROVIDE 3 PH SVC TO LIFT STATION W/IN TYPICAL SUBDIVISION - OPTION 1

CUSTOMER REQUEST: 120/208 or 277/480

	AVAILABLE UNDERGROUND FACILITIES		
MOTOR SIZE	SINGLE PHASE	TWO PHASES	THREE PHASES
< 5HP	$21.85 per ft plus 3ph padmount tx, pad, and ug service minus one oh transformer, cutout, arrester, and service	$15.30 per ft plus 3ph padmount tx, pad, and ug service minus one oh transformer, cutout, arrester, and service	$0 cost per ft plus 3ph padmount tx, pad, and ug service minus one oh transformer, cutout, arrester, and service
5HP < X < 25HP	$8.98 per ft plus 3ph padmount tx, pad, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$10.81 per ft plus 3ph padmount tx, pad, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 3ph padmount tx, pad, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service
> 25HP	$4.50 per ft plus 3ph padmount tx, pad, and ug service minus 3 oh transformers, 3 cutouts, 3 arresters, cluster mt, and service	$2.42 per ft plus 3ph padmount tx, pad, and ug service minus 3 oh transformers, 3 cutouts, 3 arresters, cluster mt, and service	$0 cost per ft plus 3ph padmount tx, pad, and ug service minus 3 oh transformers, 3 cutouts, 3 arresters, cluster mt, and service

CUSTOMER REQUEST: 120/240 OPEN DELTA

	AVAILABLE UNDERGROUND FACILITIES		
MOTOR SIZE	SINGLE PHASE	TWO PHASES	THREE PHASES
< 5HP	$11.04 per ft plus 2 padmount tx, 2 pads, and ug service minus one oh transformer, cutout, arrester, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus one oh transformer, cutout, arrester, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus one oh transformer, cutout, arrester, and service
5HP < X < 25HP	$2.08 per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service
> 25HP	$2.08 per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
Fifth Revised Sheet No. 4.26.1
Canceling Fourth Revised Sheet No. 4.26.1

PAGE	EFFECTIVE DATE

6.3.2 (continued)

THREE PHASE LIFT STATION
COSTS TO PROVIDE 3 PH SVC TO LIFT STATION W/IN TYPICAL SUBDIVISION - OPTION 2

CUSTOMER REQUEST: 120/208 or 277/480

	AVAILABLE UNDERGROUND FACILITIES		
MOTOR SIZE	SINGLE PHASE	TWO PHASES	THREE PHASES
< 5HP	$21.14 per ft plus 3ph padmount tx, pad, and ug service minus one oh transformer, cutout, arrester, and service	$14.90 per ft plus 3ph padmount tx, pad, and ug service minus one oh transformer, cutout, arrester, and service	$0 cost per ft plus 3ph padmount tx, pad, and ug service minus one oh transformer, cutout, arrester, and service
5HP < X < 25HP	$8.26 per ft plus 3ph padmount tx, pad, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$10.43 per ft plus 3ph padmount tx, pad, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 3ph padmount tx, pad, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service
> 25HP	$3.79 per ft plus 3ph padmount tx, pad, and ug service minus 3 oh transformers, 3 cutouts, 3 arresters, cluster mt, and service	$2.03 per ft plus 3ph padmount tx, pad, and ug service minus 3 oh transformers, 3 cutouts, 3 arresters, cluster mt, and service	$0 cost per ft plus 3ph padmount tx, pad, and ug service minus 3 oh transformers, 3 cutouts, 3 arresters, cluster mt, and service

CUSTOMER REQUEST: 120/240 OPEN DELTA

	AVAILABLE UNDERGROUND FACILITIES		
MOTOR SIZE	SINGLE PHASE	TWO PHASES	THREE PHASES
< 5HP	$10.71 per ft plus 2 padmount tx, 2 pads, and ug service minus one oh transformer, cutout, arrester, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus one oh transformer, cutout, arrester, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus one oh transformer, cutout, arrester, and service
5HP < X < 25HP	$1.75 per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service
> 25HP	$1.75 per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
Fifth Revised Sheet No. 4.26.2
Canceling Fourth Revised Sheet No. 4.26.2

PAGE	EFFECTIVE DATE

6.3.2 (continued)

THREE PHASE LIFT STATION
COSTS TO PROVIDE 3 PH SVC TO LIFT STATION W/IN TYPICAL SUBDIVISION - OPTION 3

CUSTOMER REQUEST: 120/208 or 277/480

	AVAILABLE UNDERGROUND FACILITIES		
MOTOR SIZE	SINGLE PHASE	TWO PHASES	THREE PHASES
< 5HP	$18.61 per ft plus 3ph padmount tx, pad, and ug service minus one oh transformer, cutout, arrester, and service	$13.64 per ft plus 3ph padmount tx, pad, and ug service minus one oh transformer, cutout, arrester, and service	$0 cost per ft plus 3ph padmount tx, pad, and ug service minus one oh transformer, cutout, arrester, and service
5HP < X < 25HP	$5.73 per ft plus 3ph padmount tx, pad, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$9.16 per ft plus 3ph padmount tx, pad, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 3ph padmount tx, pad, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service
> 25HP	$1.26 per ft plus 3ph padmount tx, pad, and ug service minus 3 oh transformers, 3 cutouts, 3 arresters, cluster mt, and service	$0.77 per ft plus 3ph padmount tx, pad, and ug service minus 3 oh transformers, 3 cutouts, 3 arresters, cluster mt, and service	$0 cost per ft plus 3ph padmount tx, pad, and ug service minus 3 oh transformers, 3 cutouts, 3 arresters, cluster mt, and service

CUSTOMER REQUEST: 120/240 OPEN DELTA

	AVAILABLE UNDERGROUND FACILITIES		
MOTOR SIZE	SINGLE PHASE	TWO PHASES	THREE PHASES
< 5HP	$9.44 per ft plus 2 padmount tx, 2 pads, and ug service minus one oh transformer, cutout, arrester, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus one oh transformer, cutout, arrester, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus one oh transformer, cutout, arrester, and service
5HP < X < 25HP	$0.49 per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service
> 25HP	$0.49 per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service	$0 cost per ft plus 2 padmount tx, 2 pads, and ug service minus 2 oh transformers, 2 cutouts, 2 arresters, and service

ISSUED BY: S. W. Connally, Jr.

GULF POWER
A SOUTHERN COMPANY

Section No. IV
Ninth Revised Sheet No. 4.28
Canceling Eighth Revised Sheet No. 4.28

PAGE	EFFECTIVE DATE

6.5 OTHER UNDERGROUND DISTRIBUTION FACILITIES

6.5.1 APPLICABILITY. This subpart applies to requests for underground facilities addressing the conversion of existing overhead facilities. In order for the Company to take action pursuant to a request for conversion:

(1) the conversion area must be at least two contiguous city blocks or 1000 feet in length;

(2) all electric services to the real property on both sides of the existing overhead primary lines must be part of the conversion; and

(3) all other existing overhead utility facilities (e.g. telephone, CATV, etc.) must also be converted to underground facilities.

6.5.2 NON-BINDING COST ESTIMATES. An Applicant may obtain a non-binding estimate of the charges the Applicant would be obligated to pay in order for the Company to provide underground distribution facilities. This non-binding estimate will be provided to the Applicant without any charge or fee upon completion of the Application for Underground Cost Estimate set forth in Section VII of this tariff, Standard Contract Forms, at Sheet No. 7.43.

6.5.3 BINDING COST ESTIMATES. An Applicant, upon payment of a non-refundable deposit and completion of the Application for Underground Cost Estimate set forth in Section VII of this tariff, Standard Contract Forms, at Sheet No. 7.43, may obtain an estimate of the charges for underground distribution facilities, which estimate the Company would be bound to honor as provided below. The deposit amount, which approximates the engineering costs for underground facilities associated with preparing the requested estimate, shall be calculated as follows:

Conversion	
Urban Commercial	$4,640 per overhead primary mile
Urban Residential	$7,554 per overhead primary mile
Rural Residential	$6,130 per overhead primary mile
210 Lot Subdivision	$5,814 per overhead primary mile
176 Lot Subdivision	$10,166 per overhead primary mile

ISSUED BY: S. W. Connally, Jr.

Item 9

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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Ollila) S.O. EJD PA J.L.D
Office of the General Counsel (Villafrate)

RE: Docket No. 150077-EU – Joint petition for approval of territorial agreement in Lake and Sumter counties by the City of Leesburg and Duke Energy Florida, Inc.

AGENDA: 06/18/15 – Regular Agenda – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Patronis

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On March 9, 2015, Duke Energy, Florida, Inc. (Duke), and the City of Leesburg (Leesburg) filed a joint petition for approval of a territorial agreement (proposed Agreement) in Lake and Sumter counties. The proposed Agreement is Attachment A to the petition while the maps are Exhibit A to the petition. Duke and Leesburg were parties to a prior territorial agreement (prior Agreement) that expired on July 22, 2013.[1] Duke and Leesburg assert that they are abiding by the terms of the prior Agreement until the Commission approves a new agreement. During its evaluation of the joint petition, staff issued one data request to the parties. The Commission has jurisdiction over this matter pursuant to Section 366.04, Florida Statutes (F.S.).

[1] Order No. 12289, issued July 22, 1983, in Docket No. 820492-EU, In re: Application of Florida Power Corporation and the City of Leesburg for approval of a territorial agreement relating to service areas.

Discussion of Issues

Issue 1: Should the Commission approve the joint petitioners' proposed Agreement?

Recommendation: Yes, the Commission should approve the proposed Agreement. (Ollila)

Staff Analysis: Pursuant to Section 366.04(2)(d), F.S., the Commission has the jurisdiction to approve territorial agreements between and among rural electric cooperatives, municipal electric utilities, and other electric utilities. Rule 25-6.60440(2), Florida Administrative Code (F.A.C.), states that in approving territorial agreements, the Commission may consider:

(a) The reasonableness of the purchase price of any facilities being transferred;

(b) The reasonable likelihood that the agreement, in and of itself, will not cause a decrease in the reliability of electrical service to the existing or future ratepayers of any utility party to the agreement; and

(c) The reasonable likelihood that the agreement will eliminate existing or potential uneconomic duplication of facilities.

Unless the Commission determines that the agreement will cause a detriment to the public interest, the agreement should be approved.[2]

According to the joint petitioners, there are three differences between the prior and proposed Agreements. First, the boundary maps have been updated to a geographical information system (GIS) format to show the boundary lines in greater detail. Second, although the terms of the prior and proposed agreements are 30 years, the proposed Agreement will remain in effect past the expiration date until and unless either party provides written notice of termination. Third, the boundary has been modified such that there will be 18 customer transfers from Leesburg to Duke.

All of the customers that are subject to transfer to Duke are general service non-demand commercial customers. Exhibit B to the petition provides a list of the customers, which includes cell towers, pump stations, and highway ramps. As of January 2015, the rate comparison for these customers, using 1,500 kwh, was $214.82 for Leesburg and $186.34 for Duke. In accordance with Rule 25-6.0440(1)(d), F.A.C., notification letters were sent to these customers on February 9, 2015; as of the recommendation's filing date neither party had received a negative response to the letter. The joint petitioners expect that all customer transfers will be completed no later than 24 months after the effective date of the proposed Agreement and will notify the Commission in writing if additional time is needed.

According to the proposed Agreement, no compensation will be paid for the transfer of customers; however the receiving party, Duke, may elect to purchase the distribution facilities used exclusively to serve the customers. In response to staff's data request, the joint petitioners explained that they have tentatively agreed to exchange and purchase the required facilities. The

[2] Utilities Commission of the City of New Smyrna v. Florida Public Service Commission, 469 So. 2d 731 (Fla. 1985).

joint petitioners have not valued the facilities but plan to as soon as practical should the Commission approve the proposed Agreement.

The proposed Agreement specifies that the purchase amount will be based on the replacement cost less depreciation and the cost to the transferring party, Leesburg, for reintegration of its remaining system where such costs are reasonably required by sound business practices. To calculate replacement costs, the proposed Agreement specifies that both parties must apply the same cost escalator (such as the Handy Whitman Index) to original cost.

The joint petitioners assert that the proposed Agreement will avoid duplication of services and wasteful expenditures and will protect the public health and safety from potentially hazardous conditions. The joint petitioners believe and represent that the Commission's approval of the proposed Agreement is in the public interest.

After review of the petition, the proposed Agreement, and the parties' response to its data request, staff believes that the proposed Agreement is in the public interest and will enable Duke and Leesburg to better serve their current and future customers. It appears that the proposed Agreement eliminates any potential uneconomic duplication of facilities and will not cause a decrease in the reliability of electric service. As such, staff believes that the proposed Agreement between Duke and Leesburg will not cause a detriment to the public interest and recommends that the Commission approve it.

Issue 2: Should this docket be closed?

Recommendation: Yes. 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.

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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Garl) ESD PD
Office of the General Counsel (Villafrate) J.W.D JSC

RE: Docket No. 150093-GU – Joint petition for approval of territorial agreement in Hardee County, by Peoples Gas System and Sebring Gas System, Inc.

AGENDA: 06/18/15 – Regular Agenda Conference – Proposed Agency Action – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Patronis

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

Case Background

On March 23, 2015, Peoples Gas System (PGS) and Sebring Gas System, Inc. (Sebring) filed a joint petition requesting Commission approval of a territorial Agreement for a portion of Hardee County located within and adjacent to the City of Wauchula, Florida. PGS provides natural gas sales and transportation service to customers in Hardee County, Florida. In addition, PGS provides gas transportation service to the gas marketer supplying natural gas to customers that are served by Sebring. PGS plans to continue expanding its distribution system in Hardee County and the surrounding area as provided in the extension of facilities policy contained in its tariff on file with the Commission.[1]

[1] Peoples Gas System Tariff, Original Volume No. 3, Fourth Revised Sheet No 5.601, effective March 13, 2012; Second Revised Sheet No. 5.601-1, effective January 6, 2004; and Second Revised Sheet No. 5.601-2, effective January 29, 2008.

Sebring provides natural gas transportation service to customers within and adjacent to the City of Sebring in Highlands County, immediately east of Hardee County. On May 12, 2014, the City of Wauchula Commission adopted Ordinance 2014-10 awarding a franchise to Sebring to provide natural gas service to residents of the city.

During its evaluation of the petition, staff issued one data request to PGS and Sebring. The questions posed by staff were intended to clarify background information about natural gas service to the City of Wauchula, some provisions of the proposed Agreement, and its impact on ratepayers of both companies. The Commission has jurisdiction over this matter pursuant to Section 366.04, Florida Statutes (F.S.).

Discussion of Issues

Issue 1: Should the Commission approve the proposed Agreement between PGS and Sebring?

Recommendation: Yes. The Commission should approve the proposed Agreement. (Garl)

Staff Analysis: Pursuant to Section 366.04(3)(a), F.S., the Commission has the jurisdiction to approve territorial agreements between and among natural gas utilities. Rule 25-7.0471, Florida Administrative Code (F.A.C.), provides that in approving territorial agreements, the Commission shall consider:

(a) The reasonableness of the purchase price of any facilities being transferred;

(b) The reasonable likelihood that the agreement, in and of itself, will not cause a decrease in the reliability of natural gas service to the existing or future ratepayers of any utility party to the agreement, and

(c) The reasonable likelihood that the agreement will eliminate existing or potential uneconomic duplication of facilities.

(d) Other relevant factors that may arise from the circumstances of a particular case.

Unless the Commission determines that the agreement will cause a detriment to the public interest, the agreement should be approved.[2]

The proposed territorial Agreement establishes the area Sebring will serve within the corporate limits of the City of Wauchula and certain adjoining areas as depicted on the map included as Attachment A to this recommendation. The Agreement specifically excludes the Hardee County Fleet Maintenance facility occupying approximately one block in the southern portion of the city, which will be served by PGS. The term of the Agreement is until termination or modification is mutually agreed to by the parties or as mandated by an entity or court of appropriate jurisdiction.

In response to staff's data request, the companies stated that natural gas service was not previously available to the City of Wauchula. As a result, there are no customers or facilities to be transferred between PGS and Sebring. Reliability of service will increase from no service to full access to natural gas service for residents of Wauchula. Furthermore, there will be no uneconomic duplication of facilities within the area to be served by Sebring, because Sebring's installation of its distribution system will be the only natural gas pipelines in the area, with the exception of the one excluded facility.

The PGS and Sebring response to the staff data request further explained that the excluded facility belongs to Hardee County. Prior to the negotiation of the PGS-Sebring territorial agreement, PGS and Hardee County had committed to the construction of a Compressed Natural Gas (CNG) station to service Hardee County vehicles. PGS will provide

[2] Utilities Commission of the City of New Smyrna Beach v. Florida Public Service Commission, 469 So. 2d 731 (Fla. 1985).

gas service to the station. The carve out of this customer from the Agreement is necessary to keep the agreements made between PGS and the customer (Hardee County) intact since construction of the CNG station has been completed. Sebring currently has no facilities near the CNG station. If necessary for Sebring to serve customers in this area, and to avoid duplication of service facilities, PGS and Sebring may establish a second interconnect on the PGS main line in this area. From that interconnect, Sebring could proceed to design and build-out their distribution facilities.

After review of the petition, the proposed Agreement, and the parties' response to a data request, staff believes that the proposed Agreement is in the public interest and will enable PGS and Sebring to better serve their current and future customers. It appears that the proposed Agreement eliminates any potential uneconomic duplication of facilities and will not cause a decrease in the reliability of natural gas service. As such, staff believes that the proposed Agreement between PGS and Sebring will not cause a detriment to the public interest and recommends that the Commission approve it.

Issue 2: Should this docket be closed?

Recommendation: Yes. 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.

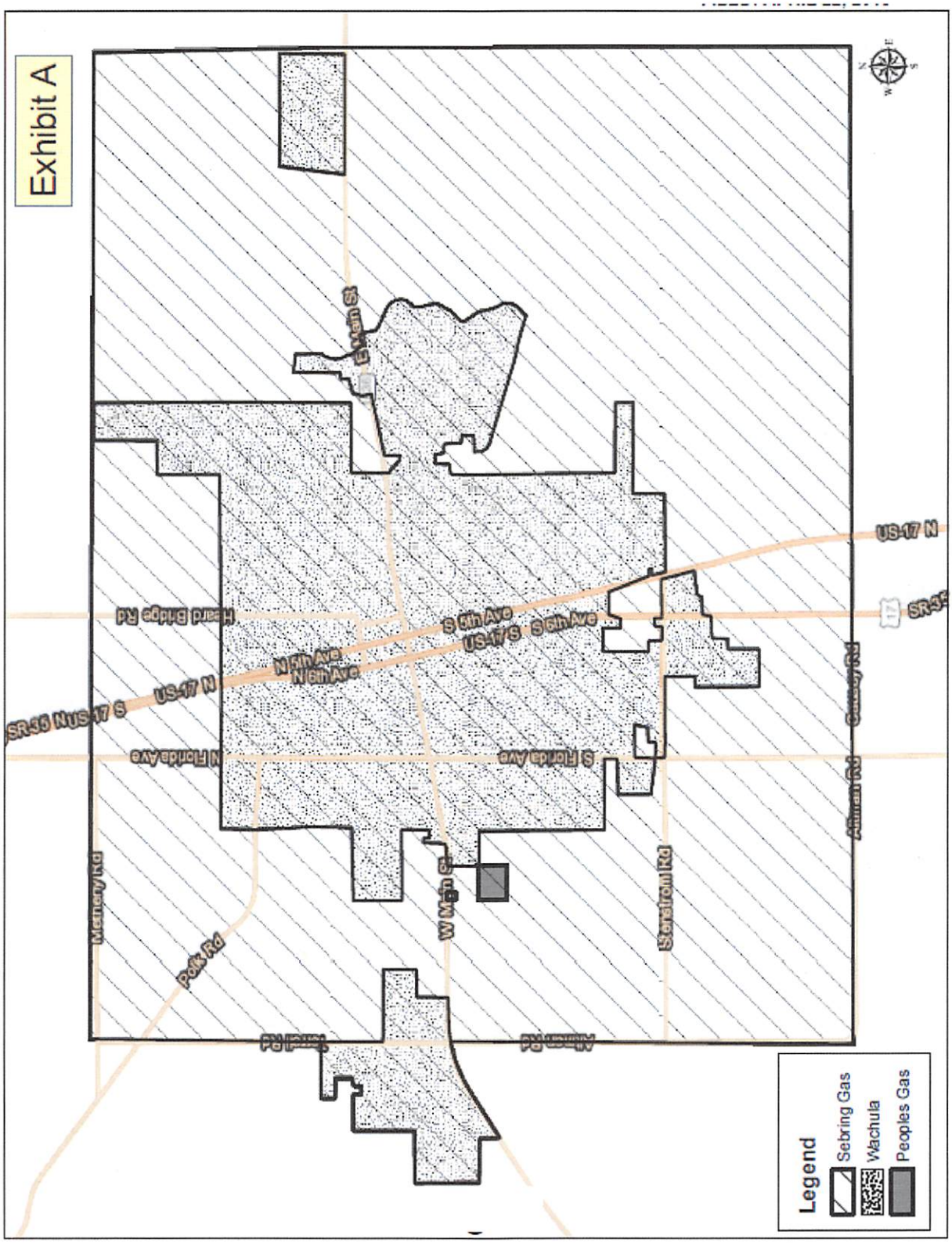


Exhibit A
E Main St
US-17 N
SR-
S 6th Ave
US-17 S
N 5th Ave
N 6th Ave
SR-35 N US-17 S
N Florida Ave
S Florida Ave
Gamble Rd
Altman Rd
Sebring Pkwy
W Main St
Memory Rd
Polk Rd
Legend
Sebring Gas
Wachula
Peoples Gas

Item 11

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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Division of Economics (Bruce, Daniel, Hudson)
Division of Accounting and Finance (Archer, Cicchetti)
Division of Engineering (Watts)
Office of the General Counsel (Crawford, Mapp)

RE: Docket No. 140158-WS – Application for increase in water/wastewater rates in Highlands County by HC Waterworks, Inc.

AGENDA: 06/18/15 – Regular Agenda – Proposed Agency Action, Except for Issue Nos. 20 and 22 – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Brisé

CRITICAL DATES: 5-Month Effective Date Waived Through 06/18/15

SPECIAL INSTRUCTIONS: None

Table of Contents

Case Background

HC Waterworks, Inc. (HC or Utility) is a Class B utility serving approximately 929 water customers in three subdivisions known as Leisure Lakes, Lake Josephine, and Sebring Lakes and 297 wastewater customers in Leisure Lakes in Highlands County. The Utility's service territory is located in the Southwest Florida Water Management District (SWFWMD). In the Utility's 2014 Annual Report, HC reported total operating revenues of $590,053 and total operating expenses of $519,944.

HC's last rate case proceeding was in Docket No. 100330-WS prior to the transfer from Aqua Utilities Florida, Inc. (Aqua) to HC.[1] Aqua's rates were based on a capband methodology in which systems were grouped together based on similar costs to serve with bills capped at a maximum affordability level. The groupings, based on similar costs to serve, were an effort to minimize the level of subsidization among customers.

By Order No. PSC-14-0314-PAA-WS, issued June 13, 2014, the Commission approved the transfer of Certificate Nos. 422-W and 359-S from Aqua to HC.[2] On October 2, 2014, HC filed its application for the rate increase at issue in the instant docket. Accompanying the Utility's application were minimum filing requirement schedules (MFRs) required by Section 367.081, Florida Statutes (F.S.), and Rule 25-30.437, Florida Administrative Code (F.A.C.). The Utility was notified of deficiencies in the MFRs on October 31, 2014. The deficiencies were corrected and December 16, 2014, was established as the official filing date.

The Utility requested that the application be processed using the Proposed Agency Action (PAA) procedure and a test year ended June 30, 2014. HC contends that its earnings are outside the range of reasonable returns. The Utility is requesting an increase to recover reasonable and prudent costs for providing service and a reasonable rate of return on investment, including the requested pro forma plant improvements. In its original application, HC requested final rates designed to generate annual revenues of $509,491 for water and $73,571 for wastewater. This represents a revenue increase of $103,463 (20.30 percent) for water and a decrease of $47,574 (64.66 percent) for wastewater.

By Order No. PSC-14-0685-PCO-WS, the Commission suspended the final rates proposed by the Utility to allow staff sufficient time to process this case.[3] A customer meeting was held on February 19, 2014. In a letter filed on March 13, 2014, the Office of Public Counsel (OPC) identified concerns with the MFRs and other information filed by HC in support of its rate

[1] Order No. PSC-12-0102-FOF-WS, issued March 5, 2012, in Docket No. 100330-WS, In re: Application for increase in water/wastewater rates in Alachua, Brevard, Desoto, Hardee, Highlands, Lake, Lee, Marion, Orange, Palm Beach, Pasco, Polk, Putnam, Seminole, Sumter, Volusia, and Washington Counties by Aqua Utilities, Florida, Inc.

[2] Order No. PSC-14-0314-PAA-WS, issued June 13, 2014, in Docket No. 130175-WS, In re: Application for approval of transfer of certain water and wastewater facilities and Certificate Nos. 422-W and 359-S of Aqua Utilities Florida, Inc. to HC Waterworks, Inc. in Highlands County.

[3] Order No. PSC-14-0685-PCO-WS, issued December 10, 2014, in Docket No. 140158-WS, In re: Application for increase in water/wastewater rates in Highlands County by HC Waterworks, Inc.

increase. Letters from customers opposing the rate increase and water quality were also filed in the docket.

On April 29, 2015, staff met with OPC and the Utility to discuss revisions made to the MFRs. At the noticed meeting, all agreed that the Utility should refile its MFRs to address these issues as well as include any pro forma projects completed after the test year. Further, the Utility also agreed to renotice the customers to give them an opportunity to provide comments on the revised filing. On May 4, 2015, HC filed revised MFRs to address the revisions made to its original filing and to include additional pro forma items which occurred after the test year. The Utility's revised requested revenues are $545,113 for water and $76,774 for wastewater. These revised revenue levels represent additional increases of $35,622 (7.00%) and $3,203 (4.35%) over the prior noticed requested revenues for water and wastewater, respectively. The Utility sent a revised customer notice to the customers on May 4, 2015. The five-month statutory deadline for the Commission to address the Utility's requested final rates was May 18, 2015. However, by letter dated June 1, 2015, the Utility waived the five-month statutory deadline through June 18, 2015.

This recommendation addresses HC's request for final rates. The Commission has jurisdiction pursuant to Sections 367.081, Florida Statutes (F.S.).

Discussion of Issues

Quality of Service

Issue 1: Should the quality of service provided by HC be considered satisfactory?

Recommendation: Yes. Staff recommends that the condition of the water and wastewater treatment facilities are satisfactory and the water provided by HC is meeting applicable water quality standards, including primary and secondary standards, as prescribed in the Florida Department of Environmental Protection (DEP) rules. It also appears that the Utility has attempted to address customers' concerns. Therefore, staff recommends that the overall quality of service for the HC water and wastewater systems in Highlands County is satisfactory. (Watts)

Staff Analysis: Pursuant to Rule 25-30.433(1), 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 operational conditions of the Utility's plant and facilities, and the Utility's attempt to address customer satisfaction. HC's compliance with the DEP and SWFWMD regulations, and customer comments or complaints received by the Commission, are also reviewed.

Quality of Utility's Product and Operating Conditions of the Utility's Plant and Facilities.

HC's service area is located in Highlands County. The raw water source is ground water, which is obtained from six wells, two in each of three service areas. The water treatment processing sequence is to pump raw water from the aquifer, force the raw water through filters (referred to hereinafter by their brand name, AdEdge), treat the water with chloramine (a mixture of chlorine and ammonia), store the treated water in a tank, and distribute.

In addition to primary contaminants, Section 367.0812, F.S., requires the Commission to consider secondary contaminants as part of the overall quality of service. Secondary contaminants are those contaminants a customer would likely notice because they impact things like color or smell. However, secondary contaminants are not a health risk and DEP does not typically undertake enforcement actions for secondary standards, unless another type of contaminant exceeds the maximum contaminant levels (MCL).

HC is current in all of its required chemical analyses. Staff reviewed the chemical analyses for both the Leisure Lakes and Lake Josephine/Sebring Lakes systems, with samples dated April 24, 2012. The laboratory tests show that HC's finished water product is below the MCLs allowed by DEP for primary contaminants and all but one secondary contaminant in the Leisure Lakes system, which was iron. Since the primary contaminants were within acceptable limits, DEP did not take action with respect to the iron content. Staff notes that no complaints have been filed by customers regarding iron. In addition, subsequent to those 2012 laboratory tests, Aqua installed the AdEdge filters which may have alleviated the iron problem. DEP requires these chemical analyses every three years, so the next test is due in 2015.

Samples taken on September 3, 2013, from both the Leisure Lakes and Lake Josephine/Sebring Lakes systems showed each system exceeded the MCLs for Total Trihalomethanes (TTHM) and Halo Acetic Acids (HAA5), also known as disinfection byproducts. These contaminants can have adverse health effects, and are tested annually unless levels exceeding the MCL are detected. When that happens, the Utility is required to issue notices to its customers and take steps to bring the water system(s) into compliance with DEP rules regarding disinfection byproducts. The Utility must then have its water systems tested quarterly until the levels are below the MCLs, and continue to test for two more quarters, issuing warning notices to customers each time. After three consecutive quarterly tests showing levels below the MCLs, the Utility is allowed to return to annual testing and to stop issuing notices to its customers.

To address this problem, in February 2014 HC converted the Leisure Lakes water treatment plant (WTP) from using free chlorine as a disinfectant to using chloramines. It proved to be effective in bringing the disinfectant byproduct levels into compliance with DEP rules. Therefore, in August 2014 it converted the Sebring Lakes WTP to chloramines, and completed the Lake Josephine conversion in September 2014. After its respective conversion, the lab results for each WTP showed acceptable levels of disinfection byproducts for three consecutive quarters, and each system has been cleared to return to annual testing. Thus, there appear to be no water quality compliance issues with this facility.

Staff also reviewed the Utility's last DEP Sanitary Survey Reports, dated September 25, 2014, for Lake Josephine/Sebring Lakes, and dated December 5, 2014, for Leisure Lakes. The Lake Josephine/Sebring Lakes report states the facility is in compliance. The Leisure Lakes report noted that the monthly operating reports (MORs) state that the system is operating over the permitted design capacity. The Utility was instructed by DEP to apply for a permit to re-rate or expand the water plant capacity. HC responded on December 22, 2014, stating that U.S. Water Engineering would perform a Capacity Analysis Report to address the issue. The Utility provided the Capacity Analysis Report to DEP on February 26, 2015. Based on HC's DEP compliance, staff recommends that the operational conditions of the WTPs are satisfactory.

The wastewater treatment plant (WWTP) is an extended aeration activated sludge facility, with chlorinated effluent sent to a percolation pond. Staff reviewed the last Compliance Evaluation Inspection performed by DEP, dated July 24, 2014. DEP stated that the lift station did not have a warning sign with an emergency telephone number posted. The Utility reported on July 25, 2014, that it had posted the required sign. When inspecting the plant, staff observed that the sign was in place. No subsequent compliance issues were reported by DEP. Based on HC's status with DEP, staff recommends that the operational condition of the WWTP is satisfactory.

The Utility's Attempt to Address Customer Satisfaction

A customer meeting was held in Sebring, Florida, on February 19, 2015. Ten of the Utility's customers attended the meeting and seven spoke. In addition to the customers who spoke at the meeting, four customers who attended the customer meeting sent written comments to the Commission. In conjunction with HC's filing of revised MFRs, the Utility sent a Revised Initial Customer Notice to its customers on May 4, 2015. Subsequent to that notice and as of

May 26, 2015, the Commission has received an additional 34 written comments, mostly from customers who did not attend the February 19, 2015 customer meeting. The majority of these customers wrote objecting to the rate increase.

Likewise, all of the customers who spoke at the customer meeting or wrote within the following three weeks were concerned about the rate increase. In addition to rates, these customers had concerns or questions about: (1) water quality and safety; (2) brown water that persisted for 11 days and damaged materials in the home; (3) low water pressure; (4) not receiving Precautionary Boil Water Notices (PBWN); and (5) the lack of available fire hydrants in the Lake Josephine area.

Water quality, safety, and brown water. All of the comments addressed the bad taste and/or smell of the water. This is due primarily to the high sulfur content of the raw groundwater. While not a primary contaminant or a health hazard, it does make the water unpleasant. The previous owner of the Utility had attempted to improve the aesthetics of the water by filtering out as much sulfur as it could with the AdEdge filters.

When HC took over operations after the transfer from Aqua, it found that the maintenance protocol instituted by the previous owner for the AdEdge filters was incorrect. The previous owner used recycled water (from previous backwashes) to backwash the filters in an attempt to clean them, which resulted in clogging the filter media, insufficient removal of the sulfur, as well as causing discoloration of the water. After researching the situation, HC determined and instituted the proper protocol for backwashing and maintaining the AdEdge filters by using clean water. The Utility meters the amount of water used for backwashing the AdEdge filters and records the amount daily.

As stated in the previous section, HC converted its WTPs to chloramines for disinfection, and tests conducted subsequent to each conversion show that the conversions were effective in bringing the contaminant levels to well below the DEP standards. However, DEP rules required HC to continue to issue the warning notices quarterly until three consecutive quarterly tests came back within the DEP standards. This appears to have caused confusion among the customers, who believed that the water was still unsafe to drink.

While the chloramine conversion corrected the problem with the TTHM/HAA5 levels, it exacerbated the secondary considerations of taste and odor for the customers. This was due to two factors: 1) the chloramines used to keep the disinfection byproduct levels low were less effective than free chlorine at disinfection, causing the chlorine residuals in the system to be too low according to DEP requirements and 2) the seasonal nature of the customer base. Because many customers are away for several months at a time, the water in some areas of the service territory would remain in the lines too long. This allowed the hydrogen sulfide (the source of the rotten egg odor) to reform in the lines, creating a chlorine demand and, thus, reducing the chlorine residual even further.

To reduce the reformation of hydrogen sulfide and to increase the chlorine residual to acceptable levels, the Utility instituted a flushing routine at appropriate points in its distribution system. Based on the historical location of problem areas, the Utility installed automatic flushers

at some points, and continued to manually flush other locations as needed. The Utility keeps a record of the quantity of water used to flush the system daily.

In flushing the system and backwashing the filters, staff believes that the Utility is taking the necessary actions to provide the best quality water possible at this location. Staff also believes that the Utility is properly monitoring and accounting for the amount of water used for these purposes.

As noted in the previous section, the most recent tests for all primary contaminants and chlorine residuals show that the water meets DEP standards and it is safe to drink. Additionally, the Utility has been diligent in its efforts to reduce the unpleasant odor and taste of the water given the naturally-occurring high sulfur content and the seasonal customer base.

Low water pressure. One customer who wrote to the Commission, noted that the Utility seemed to have frequent incidences of low water pressure. Staff reviewed DEP records regarding PBWNs, as the need to issue them can be triggered when the water pressure in the system goes below 20 psi. Staff found that HC issued PBWNs for the Leisure Lakes service area on four occasions between May 2014 and March 2015, three of which were triggered by low pressure in the system due to two line breaks and a power failure. All but one involved the entire service territory. HC issued six PBWNs for the Lake Josephine/Sebring Lakes area between September 2013 and March 2015. Four were for emergency repairs that involved a loss of pressure, and two were for preplanned repairs. All were limited to a small portion of the service territory. There does not appear to be an excessive number of low water pressure incidents, given the size of the systems.

Not receiving Precautionary Boil Water Notices. One customer at the February 19, 2015 customer meeting stated that he did not receive a PBWN one day last summer, and his wife became ill that evening. When he spoke with his neighbors the next day, he discovered that a notice had been issued the day before. He stated that, had he seen it, his wife would not have become ill.

In reviewing the PBWNs issued by the Utility, staff found that the incident described by the customer likely happened in connection with a PWBN issued on August 6, 2014, for 50 connections affected by a four-inch water line break at 10809 US Highway 27. The PBWN was rescinded on August 12, 2014, after the required number of laboratory tests were completed following the repair to the line. HC's report to DEP states that the PBWN was hand delivered to affected customers, as was the rescission notice. While not foolproof, this is a method accepted by DEP and it is generally an effective method for notifying customers. It appears that the Utility made a good faith effort to notify the customers.

Lack of available fire hydrants in the Lake Josephine area. One customer at the February 19, 2015 customer meeting expressed concern that there were no fire hydrants in the area when a neighbor's house caught fire, and the fire engine had to get water from Lake Josephine. He stated that they needed fire hydrants in the area. Under HC's tariff, private fire protection rates are available for general service customers which have a separate, dedicated fire line connection to their business. The water mains serving the Lake Josephine area vary in size from two inches to eight inches and are not suitable for the installation of fire hydrants at all customer locations

Staff notes that requirements concerning fire hydrants are under the jurisdiction of the local fire marshall.

After the customer meeting, HC met with customers who stayed behind to discuss issues they had raised. The following day, HC personally visited the customers who spoke at the meeting, except for one whom they were not able to contact, to follow up on quality of service comments made at the meeting. HC reported its actions in meeting with the customers in detail in a February 27, 2015 response to Customer Meeting and Engineering requests. Most of these customers' concerns dealt with billing issues or concerns with the disinfection byproducts in the water, and the Utility answered their questions during its follow-up visits. However, three customers in one neighborhood still had concerns with odor. The Utility increased the flushing schedule from four days per week to seven days per week in the area to resolve this issue. To date, these customers have not contacted HC again regarding the odor.

Staff reviewed the complaints in the Commission's Complaint Tracking System for the Leisure Lakes and Lake Josephine/Sebring Lakes systems from January 1, 2009, through December 31, 2013. Prior to the transfer to HC in July 2013, staff found 25 complaints for these systems filed with the Commission against the prior owner. Of these, 21 were billing complaints, 3 concerned low water pressure, and 1 customer wanted advance notice of system flushing. Subsequent to the transfer, staff found only three billing complaints. No quality of service problems were reported. The Utility resolved these complaints.

On January 15, 2015, staff sent a letter to DEP requesting information on complaints that were filed with DEP regarding these water systems from January 1, 2009, through December 31, 2013. DEP reported that it received two complaints regarding the Lake Josephine WTP during that time. One on September 30, 2011, regarding sand in the lines and low water pressure, and another on July 25, 2013, regarding sand in the pipes and smelly water. DEP reported two complaints from residents in the Leisure Lakes service territory on July 9, 2013, regarding a strong hydrogen sulfide odor. DEP investigated the complaints and ensured they were resolved. HC stated that no complaints have been filed with the Utility since it began operations as HC.

A summary of all complaints and comments received is shown in Table 1.

Table 1
Number of Complaints by Source

Subject of Complaint	PSC's Records (CATS)	Utility's Records	DEP Records	Docket Correspondence	Customer Meeting
Billing Related	24			5	
Opposing Rate Increase				33	7
Quality of Water	3		4	18	7
Quality of Service				8	2
Total*	27	0	4	64	16

* A complaint may appear twice in this table if it meets multiple categories.

Summary

Staff's analysis indicates the condition of the water and wastewater treatment facilities are satisfactory and the water provided by HC is meeting applicable water quality standards, including primary and secondary standards, as prescribed in the DEP rules. It also appears that the Utility has attempted to address the customers' concerns. Therefore, staff recommends the Commission find the overall quality of service for the HC water and wastewater systems in Highlands County is satisfactory.

RATE BASE

Issue 2: Should any adjustments be made to accumulated depreciation?

Recommendation: Yes. Accumulated depreciation for water and wastewater should be increased by $31,165 and $6,024, respectively. (Cicchetti)

Staff Analysis: Accumulated depreciation should be adjusted to reflect staff's audit findings the Utility did not dispute, retirements, and negative accumulated depreciation related to the purchase of the Utility in 2013.

Audit Finding 1 addressed certain items not reflected in the Utility's plant balances. Per Audit Finding 1, water accumulated depreciation should be decreased by $969. Per audit Finding 2, wastewater accumulated depreciation should be decreased by $24. Accumulated depreciation also should be decreased by $7,279 for the retirements associated with pro forma plant and retirements related to meter replacements.

Finally, accumulated depreciation should be decreased by $46,447 to remove the negative accumulated depreciation that was contained in certain accounts at the time the Utility was purchased from Aqua in 2013. Negative accumulated depreciation reduces accumulated depreciation and effectively increases rate base. Correspondingly, the negative acquisition adjustment associated with the purchase should be reduced by the same amount. The net effect of both adjustments is nearly zero. Writing off the negative accumulated depreciation against the acquisition adjustment will ensure there are not stranded assets on the Utility's books.

At the time HC Waterworks was purchased from AUF in 2013, two water accounts had negative depreciation totaling $40,399 and one wastewater account had negative depreciation totaling $6,048. Although uncommon, negative accumulated depreciation can occur due to the application of group depreciation and retirements being made in some instances at 75 percent of replacement cost. Usually, individual accounts with negative accumulated depreciation will be blended with the other accounts in the depreciation group and the negative accumulated depreciation will not be problematic. Furthermore, negative accumulated depreciation usually reverses over time as new investment is made in the group accounts. In the instant case, when HC was purchased from Aqua, specific plant accounts were identified and three of the accounts contained negative accumulated depreciation. Because a service company will now be operating the systems and costs will be allocated to the systems, there will not be significant investment in new trucks, tools, etc. by HC, and thus, the negative accumulated depreciation likely will not naturally reverse in the accounts over time. Such negative accumulated depreciation results in stranded assets on the books of the Utility and overstates a utility's net book value.

On March 13, 2015, OPC wrote a letter to the Commission, regarding its concerns in the docket. In the letter, OPC cited the transfer audit from Docket No. 130174-WS, the docket transferring the facilities from Aqua to HC. [4] The staff audit stated that, "Negative balances for

[4] Document No. 05755-13, Audit Control No. 13-199-2-3, report issued September 18, 2013, in Docket No. 130175-WS, In re: Application for approval of transfer of certain water and wastewater facilities and Certificate Nos. 422-W and 359-S of Aqua Utilities Florida, Inc. to HC Waterworks, Inc. in Highlands County.

accumulated depreciation are not a normal occurrence and in this case was not an issue until the Lake Josephine and Leisure Lakes systems were divested from the AUF water and wastewater rate band groupings. Such negative balances create a stranded asset with an indeterminable life on the utility's books and effectively overstate a utility system's net book value."

On April 3, 2015, staff held a noticed meeting to discuss, with interested parties, OPC's concerns. The meeting resulted in general agreement that the Utility should write off the negative accumulated depreciation against the negative acquisition adjustment thereby removing the negative accumulated depreciation from the Utility's books and correspondingly reducing the negative acquisition adjustment by the same amount. Staff recommends the Utility credit Account 341.50, Transportation Equipment, $20,000; credit Account 343.50, Tools, Shop & Garage Equipment, $20,952; credit Account 382.40, Outfall Sewer Lines, $6,139; and debit Account 114, Utility Plant Acquisition Adjustment (net), $46,447.

Staff recommends accumulated depreciation for water and wastewater be increased by $31,165 and $6,024, respectively. In summary, accumulated depreciation should be adjusted to reflect audit findings the Utility did not dispute, retirements, and negative accumulated depreciation associated with the purchase of the Utility in 2013. The recommended adjustments to accumulated depreciation are listed below in Table 2.

Table 2
Adjustments to Accumulated Depreciation

Description	Water Amount	Wastewater Amount
Per Audit Finding 1	$969	$0
Per Audit Finding 2	$0	$24
Retirement on Meter Replacements	$986	
Depreciation Associated with Pro Forma Items Addressed in Audit	$7,279	$0
Negative Accumulated Depreciation	($40,399)	($6,048)
Total	($31,165)	($6,024)
*Negative amounts indicate an increase to accumulated depreciation.		

Issue 3: Should any adjustments be made to the Utility's test year rate base?

Recommendation: The Utility's test year water rate base should be increased $1,546 and the Company's test year wastewater rate base should be increased $52. (Cicchetti)

Staff Analysis: Per the staff audit, $1,546 should be added to the Utility's test year water rate base to address certain items that had not been included in the Utility's plant balances. The $1,546 adjustment represents the simple average of an increase of $3,091. Similarly, an adjustment of $52 should be made to the Utility's test year wastewater rate base. The adjustment of $52 is the simple average of an increase of $103. Per the staff audit, the water CIAC simple average balance should be increased by $500. The accounts adjusted are listed below in Table 3.

Table 3
Rate Base Adjustments Per Staff Audit

Water Account	Description	Date in Service	Cost
301 Organization	Legal fees regarding Utility incorporation	6/26/14	$327
301 Organization	Transfer balance recorded wrong account	3/28/13	($298)
302 Franchises	Transfer balance recorded in correct account	3/28/13	$298
331 T&D Mains	Repair of broken water main	5/23/14	$1,978
335 Hydrants	Replaced hydrant	6/6/14	$3,144
335 Hydrants	Retire replaced hydrant at 75%	6/6/14	($2,358)
271 Water CIAC	Adjust simple average balance		$500
Wastewater Account	Description	Date in Service	Cost
351 Organization	Legal fees regarding Utility incorporation	6/26/14	$103

Issue 4: Should any adjustments be made to the Utility's pro forma plant additions?

Recommendation: Yes. The appropriate amount for pro forma plant additions is $41,246, net of retirements. (Cicchetti)

Staff Analysis: In its original filing, the Utility requested $23,425 of pro forma plant offset by associated retirements of $17,002 ($23,425 x .75). An additional $11,643 of pro forma plant was identified during the audit. These pro forma items were offset by associated retirements at 75 percent of $10,482, or $7,862. During the engineering inspection, $20,108 of pro forma plant related to the conversion of disinfection from free chlorines to chloramines at the Lake Josephine and Sebring Lakes water treatment facilities were identified. There are no offsetting retirements for the chloramine conversion costs because they are new, additional facilities that are not replacing existing facilities. Engineering staff has indicated these plant costs and the associated chemical costs are in addition to current costs. The Utility's revised filing, filed May 4, 2015, identified total pro forma plant additions of $38,451 net of retirements. The revised amount included additional completed projects and adjusted certain estimates to recognize final invoices. Staff adjusted the Utility's revised amount to recognize a retirement amount of $986 associated with meter replacements. The difference between the $41,246 shown in the table below and the $38,451 shown in HC's revised MFRs is the $11,643 identified in the audit minus the $7,862 for retirements minus the $986 for meter retirements ($38,451 + $11,643 - $7,862 - $986 = $41,246). The Utility has provided invoices for all of the pro forma plant additions. The following table lists the pro forma plant additions.

Table 4
Pro Forma Plant Additions

Description	Amount
Covered Bridge float switch	$755
Well pump at well #2, LL WTP*	$8,703
20 HP soft starter, LJ water plant*	$1,140
Generator automatic switch, LL*	$4,161
Generator automatic switch, LJ*	$5,125
Well #2, Lake Josephine*	$4,921
Generator automatic transfer switch*	$4,573
Generator automatic transfer switch*	$5,909
Viburnum and eucalyptus mulch	$1,161
Sebring Lakes chloramine treatment	$8,059
Service/Main leak repair, Ven. Pkwy	$4.040
Service line repair, Jasmine Street	$792
Service line repair, Park View Circle	$5429
Meter Replacements	$1314
Lake Josephine chloramine treatment	$12,049
Retirements at 75 percent	($26,885)
Net Plant Additions	$41,246
*Retirement at 75 percent	

All of the Utility's pro forma plant additions have been placed in service and invoices have been provided to verify the costs. Staff recommends the appropriate amount for pro forma plant additions is $41,246, net of retirements.

Issue 5: What are the used and useful percentages for the Utility's water and wastewater treatments, storage, distribution, and collection systems?

Recommendation: HC's WTPs should be considered 89.9 percent used and useful (U&U); its storage should be considered 100 percent U&U; its water distribution system should be considered 95.3 percent U&U; its WWTP should be considered 48.3 percent U&U; and its wastewater collection system should be considered 93.9 percent U&U. Staff recommends that wastewater purchased power and chemical expenses should be reduced by 8.05 percent for excessive infiltration and inflow (I&I). No adjustment is recommended for excessive unaccounted for water (EUW). Application of the U&U percentages to the average plant balances and the associated average accumulated depreciation balances results in a reduction to plant of $92,788 for water and $135 for wastewater. (Watts, Cicchetti)

Staff Analysis: The HC system is composed of three water systems (Leisure Lakes, Sebring Lakes, and Lake Josephine) and one wastewater system (Leisure Lakes). In October 2002, the Sebring Lakes system was interconnected with the Lake Josephine system to enable it to provide water to Lake Josephine customers as needed. In 2010, the valve connecting the Sebring Lakes and Lake Josephine systems was permanently opened to remedy system pressurization problems in the Lake Josephine water system. From that point forward, the two systems have been treated as one system by both DEP and the Commission. The capacities and characteristics of the respective component systems is shown in Table 5 below. The hydropneumatic tank at Sebring Lakes is used for system pressurization. Each of the systems uses chloramine for disinfection and AdEdge filters for sulfur removal.

Table 5
HC Waterworks Water Treatment and Distribution Facilities

		Lake Josephine		Sebring Lakes		Leisure Lakes	
WTP		Diameter	Capacity	Diameter	Capacity	Diameter	Capacity
	Well 1	8-inch	350gpm	10-inch	350gpm	8-inch	200gpm
	Well 2	8-inch	350gpm	10-inch	350gpm	4-inch	50gpm
	Total capacity:		700gpm		700gpm		250gpm
Storage		71,000 gal ground		15,000 gal ground 10,000 hydro		50,000 gal ground	
Distribution	8-inch PVC	715 linear feet		2,274 linear feet			
	6-inch PVC	15,334 linear feet		13,725 linear feet		10,546 linear feet	
	4-inch PVC	34,713 linear feet		3,025 linear feet		3,992 linear feet	
	3-inch PVC	14,205 linear feet					
	2-inch PVC	9,240 linear feet		2,140 linear feet		115 linear feet	
Hydrants		2		2		7	

Source: HC MFRs and data request responses; DEP reports

The Leisure Lakes WWTP is a 50,000 gallon per day (gpd) extended aeration activated sludge facility. The chlorinated effluent is disposed of in a two-cell rapid infiltration basin (percolation pond). The collection system is a network of force mains, collecting mains, and one lift station. The force mains consist of approximately 989 linear feet of 4-inch PVC pipe. The

collecting mains consist of approximately 13,567 linear feet of 8-inch PVC pipe. According to the Utility, there are 47 manholes.

HC's three WTPs, and their associated storage and distribution systems, were initially owned and operated independently of one another, and in their respective rates cases over the years the Commission has assigned each one different U&U percentages as were appropriate. Staff's analysis first considered the systems separately, then combined them using a weighted average to obtain a single U&U percentage for each component of the total system.

Excessive Unaccounted for Water

Rule 25-30.4325 (1)(e) , F.A.C., defines EUW as unaccounted for water in excess of 10 percent of the amount produced. Unaccounted for water is all water that is produced that is not sold, metered, or accounted for in the records of the Utility. Rule 25-30.4325(10), F.A.C., provides that to determine whether adjustments to plant and operating expenses, such as 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 purposes, such as flushing, and the gallons sold to customers from the total gallons pumped for the test year.

For the Leisure Lakes water system, the Utility's records indicated 21,202,786 gallons of water were produced during the test year, 5,570,000 gallons of water were sold to customers, and 13,879,154 gallons were used for other purposes. Thus, unaccounted for water is 8.3 percent of the amount produced, resulting in no EUW for this system.

For the Lake Josephine/Sebring Lakes water system, the Utility's records indicated 57,025,500 gallons of water were produced during the test year, 24,709,000 gallons of water were sold to customers, and 26,954,556 gallons were used for other purposes. Thus, unaccounted for water is 9.2 percent of the amount produced, resulting in no EUW for this system. Since neither system has EUW, there is no EUW for the combined system.

The amount of system flushing required to maintain the chlorine residual and the "freshness" of the water in the lines, together with the water necessary for backwashing the AdEdge filters, contributes to what appears to be an excessive amount of water (65.5 percent for Leisure Lakes and 47.3 percent for Lake Josephine/Sebring Lakes) used for "other purposes." The Utility reported the amount of water used for each purpose in its Water Audit Report submitted to SWFWMD in September 2014. SWFWMD expressed concerns via email about the amount of water used for flushing and backwashing. However, SWFWMD records indicate the Utility is actively working with SWFWMD to address its concerns. Staff notes that SWFWMD has not issued any formal citations in the matter.

Water Treatment Plant Used & Useful

Pursuant to Rule 25-30.4325(8), F.A.C., the U&U percentage of a WTP with storage is calculated by dividing the peak system demand by the firm reliable capacity (FRC). The system demand is based on the single maximum day in the test year less EUW, plus a fire flow and a growth allowance.

In the Order for the last rate case involving these systems (Order No. PSC-12-0102-FOF-WS, referenced in footnote 1, and hereinafter referred to as the Aqua Order), the Leisure Lakes WTP was stipulated to be 100 percent U&U. The Lake Josephine and Sebring Lakes WTPs had been separate Aqua systems with separate U&U percentages assigned. In the Aqua Order, since the two systems were permanently interconnected and treated as one system, the Commission assigned a U&U percentage of 85 percent based on a weighted average for the combined system. In the instant docket, staff calculated U&U percentages for the Leisure Lakes and Lake Josephine/Sebring Lakes WTPs and distribution systems, and combined them using a weighted average. The U&U analysis for each system will be discussed separately below, and the weighted average will be applied to the results.

Lake Josephine/Sebring Lakes WTP

Because the Utility has storage capacity for both the Leisure Lakes and Lake Josephine/Sebring Lakes systems, the FRC for each system is based on 16 hours of pumping excluding the largest well. The Lake Josephine WTP has two wells with a capacity of 350 gpm each, and the Sebring Lakes WTP also has two wells with a capacity of 350 gpm each. The four wells together have the capacity to pump 1,400 gpm. However, the AdEdge filters constrain the Utility to pumping a maximum of 200 gpm from each well to prevent damage to the filters, effectively limiting the maximum capacity of the four wells to 800 gpm. Thus, excluding one of the wells, the Lake Josephine/Sebring Lakes FRC is 576,000 gpd (600 gpm x 60 min/hr x 16 hrs).

The peak day of 395,400 gallons, which occurred on July 1, 2013, appears to be appropriate since it is not associated with unusual occurrences. Fire flow for the Utility's service area is 750 gpm for 2 hours, or 90,000 gpd. As discussed above, the Utility's EUW is zero. Pursuant to Rule 25-30.431, F.A.C., a linear regression analysis of the Utility's historical growth pattern results in 18 equivalent residential connections (ERCs) for the five-year statutory growth period. The Utility had an average of 649 ERCs for the test year, resulting in 609 gpd/ERC (395,400gpd/649ERCs). Thus, a growth allowance of 10,962 gpd is also considered. Therefore, calculating the U&U percentage pursuant to Rule 25-30.4325, F.A.C., yields 86.2 percent U&U for the Lake Josephine/Sebring Lakes WTP. [(395,400 gpd – 0 gpd + 90,000 gpd +10,962 gpd)/576,000 gpd]

Leisure Lakes WTP

The Leisure Lakes WTP has one well with a capacity of 200 gpm and one well with a capacity of 50 gpm each. Thus, excluding the larger well and using the equation for systems with storage, the Leisure Lakes FRC is 48,000 gpd (50 gpm x 60 min/hr x 16 hrs).

The peak day of 250,000 gallons, which occurred on June 30, 2014, appears to be appropriate since it is not associated with unusual occurrences. Fire flow for the Utility's service area is 500 gpm for 2 hours, or 60,000 gpd. As discussed above, the Utility's EUW is zero. Pursuant to Rule 25-30.431, F.A.C., a linear regression analysis of the Utility's historical growth pattern results in 23 ERCs for the five-year statutory growth period. The Utility had an average of 300 ERCs for the test year, resulting in 833 gpd/ERC (250,000gpd/300ERCs). Thus, a growth allowance of 19,159 gpd is also considered. Therefore, calculating the U&U percentage pursuant to Rule 25-30.4325, F.A.C., yields 100 percent U&U for the Leisure Lakes WTP. [250,000 gpd – 0 gpd + 60,000 gpd +19,159 gpd)/48,000 gpd]

Consolidated HC WTP system

As discussed previously, the Commission previously combined the Lake Josephine and Sebring Lakes WTP U&U percentages by applying a weighted average to the separate U&U percentages for each system. Following the same procedure, staff recommends that the consolidated HC WTP system be considered 89.9 percent U&U. [(72.9 x 86.2 + 27.1 x 100)/(72.9 + 27.1) = 89.9%, based on percentage of water pumped for each system]

Storage Used & Useful

Pursuant to Rule 25-30.4325(8), F.A.C., for water systems with storage, if the storage capacity is less than the peak demand, the storage system should be considered 100 percent U&U. For HC, since the storage capacity for each system (86,000 gallons for Lake Josephine/Sebring Lakes, and 50,000 gallons for Leisure Lakes) is less than the peak demand (395,400 gallons for Lake Josephine/Sebring Lakes, and 250,000 gallons for Leisure Lakes), the storage system should be considered 100 percent U&U.

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. 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. 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 WWTP 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 a WWTP 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 13,567 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 3,751,481gpy.

[500gpd x 8 x (13,567ft/5,280ft/mi)] x 365days/year = 3,751,481gpy

The Utility's records indicated that it billed for wastewater based on 5,517,000 gallons of water demand for its residential customers during the test year. Thus, the allowance for inflow is 10 percent of that amount, or 551,700gpy. Therefore, the total allowance for inflow and infiltration is 4,303,181gpy.

3,751,481gpy +551,700gpy = 4,303,181gpy

The Utility reported the total number of water gallons billed to all wastewater customers during the test year was 5,570,000 gallons (5,517,000 residential, 53,000 non-residential). Estimating the residential return at 80 percent and the non-residential return at 90 percent, the total estimated return to the WWTP is 4,461,300 gallons. Thus, the estimated maximum amount of wastewater that the WWTP should treat, the estimated return plus the allowable I&I, is 8,764,481 gpy. Any amount treated in excess of this amount is considered excessive I&I.

According to the Utility's Discharge Monitoring Reports filed with DEP, the Utility treated 9,532,000 gallons of wastewater during the test year. This is greater than the estimated maximum amount allowable. Therefore, the excessive I&I is 767,519 gpy.

9,532,000gpy - 8,764,481gpy = 767,519gpy

Expressed as a percentage of wastewater treated, it is 8.05 percent.

767,519gpy/9,532,000gpy = 8.05%, or 3,614 gpd

Thus, an 8.05 percent adjustment to wastewater purchased power and chemical operation and maintenance expenses should be made for excessive I&I.

Wastewater Treatment Plant

Pursuant to Rule 25-30.432, F.A.C., the U&U analysis of the 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. HC's WWTP is permitted on the basis of Annual Average Daily Flow. 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 18.5 ERCs for the five-year statutory growth period. The Utility had an average of 297 ERCs for the test

year, resulting in 87.9 gpd/ERC (26,115 gpd/297 ERCs). Thus, a growth allowance of 1,626 gpd is also considered. Based on the annual average daily flow during the test year of 26,115 gpd, the DEP permitted plant capacity of 50,000 gpd, the growth allowance of 1,626 gpd, the excessive I&I of 3,614 gpd, and pursuant to Rule 25-30.432, F.A.C., staff recommends that the WWTP be considered 48.3 percent U&U. [(26,115 gpd -3,614 gpd + 1,626 gpd)/50,000 gpd]

Water Distribution and Wastewater Collection Systems

The used and useful calculations for the water distribution and the wastewater collection systems are based on the number of customers connected to the systems divided by the capacity of the systems, consideration is given for growth. As with the Utility's WTP systems, staff calculated the Leisure Lakes and Lake Josephine/Sebring Lakes distribution systems' U&U percentages separately, then applied a weighted average to obtain the system U&U percentage.

The Lake Josephine/Sebring Lakes distribution system had 625 test year connections, 678 lots fronting mains, and a growth allowance of 18 connections, yielding a 94.8 percent U&U. [(625 + 18)/678] The Leisure Lakes distribution system had 300 test year connections, 335 lots fronting mains, and a growth allowance of 23 connections, yielding a 96.4 percent U&U. [(300 + 23)/335] Applying the weighted average, staff recommends that HC's water distribution system be considered 95.3 percent U&U. [(66.9 x 94.8 + 33.1 x 96.4)/(66.9 + 33.1) = 95.3%, based on percentage of lots connected for each system]

For the wastewater collection system, the Utility had 296 test year connections, 335 lots fronting mains, and a growth allowance of 18.5 connections. Therefore, staff recommends that the Utility's wastewater collection system be considered 93.9 percent U&U. [(296 + 18.5)/335]

Summary

Based on the analysis above, staff recommends HC's WTP should be considered 89.9 percent U&U; its storage should be considered 100 percent U&U; its water distribution system should be considered 95.3 percent U&U; its WWTP should be considered 48.3 percent U&U; and its wastewater collection system should be considered 93.9 percent U&U. Staff recommends that wastewater purchased power and chemical expenses should be reduced by 8.05 percent for excessive I&I. No adjustment is recommended for EUW. Application of the U&U percentages to the average plant balances and the associated average accumulated depreciation balances results in a reduction to plant of $92,788 for water and $135 for wastewater.

Issue 6: What is the appropriate working capital allowance?

Recommendation: The appropriate amount of working capital is $38,606 for water and $9,432 for wastewater. (Cicchetti, Archer)

Staff Analysis: Working capital is defined as the short-term investor supplied funds necessary to meet the operating expenses of the utility. Consistent with Rule 25-30.433(2) F.A.C., as applicable to Class B water and wastewater utilities, the one-eighth of operation and maintenance expense (O&M) approach was used to determine the working capital allowance. Applying this approach, staff recommends a working capital allowance of $38,606 ($308,850/8) for water and $9,432 ($75,454/8) for wastewater. Staff increased the Utility's requested working capital allowance by $338 for water and decreased the working capital allowance by $63 for wastewater to achieve one-eighth of staff's recommended O&M expense.

Staff recommends the appropriate amount of working capital is $38,606 for water and $9,432 for wastewater.

Issue 7: What are the appropriate water and wastewater rate bases for the test year ended June 30, 2014?

Recommendation: The appropriate water rate base for the test year ended June 30, 2014 is $1,835,835 for water and the appropriate wastewater rate base is $48,180. (Cicchetti, Archer)

Staff Analysis: The appropriate components of the Utility's rate base include utility plant in service, land, contributions-in-aid-of-construction (CIAC), accumulated depreciation, amortization of CIAC, and working capital. In its revised MFR's, the Utility recorded rate base of $1,919,146 for water and $45,460 for wastewater. Staff has calculated water and wastewater rate bases using the Utility's revised MFRs with adjustments as recommended in the preceding issues. Accordingly, staff recommends that the appropriate rate base for the test year ended June 30, 2014 is $1,835,835 for water and $48,180 for wastewater. Staff's recommended water and wastewater rate bases are shown on Schedule Nos. 1-A and 1-B, respectively. Staff's adjustments are shown on Schedule 1-C.

COST OF CAPITAL

Issue 8: What is the appropriate return on equity?

Recommendation: Based on the Commission leverage formula currently in effect, the appropriate allowed return on common equity (ROE) is 9.52 percent with an allowed range of plus or minus 100 basis points. (Cicchetti, Archer)

Staff Analysis: The ROE included in the Utility's MFR's is 9.52 percent. Based on the current leverage formula in effect and an equity ratio of 67.48 percent, the appropriate ROE is 9.52 percent.[5] Staff recommends an allowed return on common equity of 9.52 percent with a range of plus or minus 100 basis points be approved for ratemaking purposes.

[5] Order No. PSC-14-0272-PAA-WS, issued May 29, 2014, in Docket No. 140006-WS, In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4) (f), F.S.

Issue 9: 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 June 30, 2014?

Recommendation: The appropriate weighted average cost of capital for the test year ended June 30, 2014 is 7.79 percent. (Cicchetti)

Staff Analysis: In its filing, the Utility requested an overall cost of capital of 7.79 percent. Staff reviewed the Utility's MFR's, balance sheet, and amounts and cost rates relating to the capital structure and overall rate of return and, other than reconciling rate base to the capital structure, made no adjustments to the Utility's request.

Staff recommends the appropriate weighted average cost of capital for the test year ended June 30, 2014 is 7.79 percent. 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 June 30, 2014 are shown on Schedule No. 2.

NET OPERATING INCOME

Issue 10: What are the appropriate amounts of test year revenues for the Utility's water and wastewater systems?

Recommendation: The appropriate amount of test year revenues for HC's water and wastewater systems are $439,875 and $121,099, respectively. (Bruce)

Staff Analysis: In its MFRs, HC's adjusted test year revenues were $395,654 for water and $121,146 for wastewater. The water revenues included $380,490 of service revenues, $13,021 of miscellaneous revenues, and $2,144 of revenues from Allowance for Funds Prudently Invested (AFPI) charges. The wastewater revenue of $121,146 consisted of only service revenues. In review of the Utility's adjusted test year revenues for water, staff found that the Utility understated test year revenues by reversing a prior period accrual of $48,000. In addition, the Utility used incorrect billing determinants in each rate block when calculating test year service revenues. Also, the Utility adjusted the incorrect rate block when issuing customer credits during the test year.

Based on the appropriate billing determinants, staff applied the current rates in effect and determined that the service revenues should be increased by $44,242 for water and decreased by $47 for wastewater. Therefore, total service revenues for the water and wastewater systems should be $424,732 and $121,099, respectively. The Utility recorded $13,021 for miscellaneous revenues for the water system. Staff determined that the miscellaneous revenues should be $13,810 and were increased by $789. The Utility recorded revenues from AFPI charges of $2,144; however, staff determined those revenues should be $1,333, a decrease of $811. There are no miscellaneous revenues for the wastewater system. Based on the above, staff recommends that the appropriate amount of test year revenues for HC's water and wastewater systems are $439,875 ($424,732 +13,810+ $1,333) and $121,099, respectively.

Issue 11: Should any adjustments be made to the Utility's test year operations and maintenance expenses?

Recommendation: Yes. Operation and maintenance expenses should be decreased $226 for water and increased $364 for wastewater. (Cicchetti, Archer)

Staff Analysis: In its filing, the Utility requested recovery of contractual costs for operations and administrative services of $197,447 for water and $58,362 for wastewater. The outside services contract amount is with an affiliated company, U.S. Water Services Corporation (USWSC). On March 13, 2015, OPC filed a second letter delineating a list of concerns regarding contract costs. Certain of the costs are allocated to multiple systems and certain costs are directly assigned to HC Waterworks. OPC's concerns related to both allocated administrative costs applicable to multiple systems and to costs directly assigned from USWSC to HC Waterworks. On March 19, 2015, the Utility filed a letter with the Commission Clerk responding to OPC's concerns regarding the contract costs. Staff reviewed OPC's concerns and the Utility's response and concluded that certain allocated administrative expenses should be adjusted.

Based on its review, staff recommends adjustments be made to the management services contract amount for both water and wastewater administrative cost of salaries, fuel, and for vehicle maintenance. Staff's recommended adjustments are addressed below.

Allocated Administrative Expenses

Salaries

Allocated administrative expense included salaries for two positions-Utility Manager and Accountant. Overtime of five percent was included for these salaried positions. The Utility indicated this was an oversight. Administrative expenses are allocated on the basis of ERCs. Staff reduced the administrative cost for salaries by $999 for water and $306 for wastewater based on the total amount of the adjustment and the ratio of water and wastewater ERCs to total ERCs.

Vehicles-Fuel

Allocated vehicle fuel expense was based on a cost of $1,100 per month or $13,200 annually. The Utility indicated its most recent analysis showed the cost should be $479 per month or $5,748. Staff reduced allocated fuel expense by $1,379 annually for water and $422 annually for wastewater based on the total amount of the adjustment and the ratio of HC Waterworks water and wastewater ERCs to total ERCs.

Vehicles-Maintenance

Allocated vehicle maintenance expense was based on an annual cost of $2,400 for each vehicle. The Utility indicated the actual 2014 cost for vehicle maintenance was $1,204 per vehicle. Staff reduced allocated vehicle maintenance expense by $222 for water and $68 for wastewater based on the total amount of the adjustment and the ratio of HC Waterworks water and wastewater ERCs to total ERCs.

Total Cost of the Management Services Contract

In response to staff's second data request regarding officer's salaries, the Utility emphasized that the CEO of HC has considerable management and operator experience and expertise that is especially beneficial to a small company such as HC Waterworks. HC Waterworks maintains no hourly employees, vehicles, computers, or offices.

The services provided by USWSC include:

- Water Operations (water treatment plant, filtration, etc.)
- Wastewater Operations
- Meter Reading
- System Maintenance (water and wastewater)
- Flushing (distribution system)
- Lift Station Maintenance and Operation
- Billing and Collection
- Customer Service
- Service Orders
- Regulatory Relations (FPSC, DEP, WMD)
- Permitting (DEP, DOH, WMD, etc.)
- Testing (all testing required for water and wastewater)
- Monthly Reporting (DMR's, MOR's)
- Annual Reporting (FPSC annual report, CCR's)
- Accounting (all bookkeeping, record keeping, accounts receivable, accounts payable, etc.)
- Meter Replacements
- Line Break Repairs
- Minor Repairs and Replacements (up to $400)
- Locates, Meter Calibrations (water and wastewater)
- Backflow Preventor Testing
- Turn-Ons and Turn-Offs
- Disconnections
- Re-Reads
- Generator Maintenance
- Tank Inspections
- Vehicles, and Office
- Office Equipment (phones, computers, etc.)

The requested contract cost of $197,447 for water and $58,362 for wastewater equates to $214 per ERC for water and $206 per ERC for wastewater for a total average cost of $212 per ERC. After the adjustments recommended above of $2,600 ($999 + $1,379 + $222) to water and $796 ($306 + $422 + $68) to wastewater, the per ERC cost is $211 for water and $203 for wastewater for an average cost of $209 per ERC. These amounts are comparable to the amounts allowed in Docket No. 130194-WS[6], which were $205 per ERC for water and $200 per ERC for wastewater for a total average cost of $203 per ERC. In a letter dated December 9, 2014, the Utility presented evidence that the cost per ERC to HC compares favorably to similar Florida Governmental Utility Authority (FGUA) contracts with USWSC which were priced at $264 per ERC and to contracts evaluated in an American Water Works Association (AWWA) study which ranged from $269 to $383 per ERC for water and $295 to $478 per ERC for wastewater. The AWWA study also indicated that for small water and wastewater utilities (0-10,000 customers) the cost per ERC ranged even higher from $716 to $1,130 per ERC. Finally, the Utility states in its letter, "If HCWW was required to establish a stand-alone utility with personnel for maintenance, customer service, accounting, regulatory compliance, etc. the costs would far exceed the amount in the current USWSC contract."

The USWSC provided its costing and allocation model to the staff and OPC. Staff reviewed the model and its inputs and allocation procedures and, with the exception of the items for which staff has made adjustments, found the model to be reasonable. In particular, evaluation of the model revealed USWSC added 1,000 projected ERCs to total ERCs which serves to spread the costs over a larger base and lowers the cost per ERC. USWSC indicated it does this to recognize potential future ERCs that are expected to be added through growth or acquisitions. Additionally, USWSC did not include any salary for the Manager of Regulated Utilities in administrative services cost. The Utility stated that excluding this salary lowers costs to customers.

In conclusion, staff believes the adjusted cost of the management services contract with USWSC is reasonable. The contract cost is comparable to the cost allowed in Lakeside Waterworks, Inc.'s rate case, Docket No. 130194-WS, and is lower than similar contract costs that have been identified. USWSC and its managers bring considerable management and operator experience and expertise at a comparably reasonable cost. By spreading costs over multiple systems, and adding ERCs to recognize potential future growth, HC Waterworks' customers are realizing operational and cost benefits that would not be available if the Utility operated on a stand-alone basis. Staff recommends that the adjusted total cost of the management services contract of $194,847 for water and $57,566 for wastewater be approved.

Conclusion

Based on the analysis of the Utility's filing and responses to data requests, staff recommends total O&M expense of $308,847 for water and $75,454 for wastewater. These

[6] See Order No. PSC-15-0013-PAA-WS, issued January 2, 2015, in Docket No. 130194-WS, In re: Application for staff-assisted rate case in Lake County by Lakeside Waterworks, Inc.

amounts represent a decrease of $226 for water O&M expense and an increase $364 for wastewater O&M expense.

Issue 12: Should any adjustments be made to the Utility's test year wastewater chemical and purchased power expenses for inflow and infiltration (I&I)?

Recommendation: Yes. Wastewater chemicals and purchased power expenses should be decreased $320 and $245, respectively, for a total adjustment of $565 for excessive I&I. (Watts, Cicchetti, Archer)

Staff Analysis: Rule 25-30.432, F.A.C., provides that in determining the amount of used and useful plant, the Commission will consider I&I. Typically, infiltration results from ground water 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. The allowance for infiltration is 500 gpd per inch diameter pipe per mile, and an additional 10 percent of water sold is allowed for inflow. As addressed in Issue 5, staff recommends an excessive inflow and infiltration percentage of 8.05 percent. As a result, staff reduced wastewater purchased power expense by $320 and chemicals expense by $245 for a total reduction of $565 to address excessive I&I.

Issue 13: Should any adjustments be made to the Utility's depreciation expense?

Recommendation: Yes. Depreciation expense should be decreased $8,158 for water and increased $4,757 for wastewater. (Cicchetti, Archer)

Staff Analysis: Per staff Audit Findings 1 and 2, which the Utility did not dispute, increases of $36 for water and $357 for wastewater should be added to the Utility's test year depreciation expense to address certain items associated with plant balances. Per staff Audit Finding 9, which the Utility did not dispute, wastewater CIAC amortization expense should be decreased by $4,568 to recognize the correct composite rate. This results in an increase in wastewater depreciation expense of $4,568. Water depreciation expense also should be increased $58 to recognize the additional pro forma items identified in the audit and decreased $8,252 for water and $168 for wastewater to recognize staff's adjustments to the used and useful percentages. The net result of these adjustments is a decrease of $8,158 for water depreciation expense and an increase of $4,757 for wastewater depreciation expense.

Issue 14: Should any adjustments be made to the Utility's amortization expense?

Recommendation: Yes. Amortization expense associated with the negative acquisition adjustment should be decreased $9,660 for water and $3,456 for wastewater. (Cicchetti, Archer)

Staff Analysis: As discussed in Issue 2, the Utility's negative acquisition adjustment was reduced to reflect the elimination of negative accumulated depreciation. Consequently, the amortization of the negative acquisition adjustment also should be reduced. Staff has reduced the amortization of the negative acquisition adjustment by $3,938 for water and $3,182 for wastewater to recognize the reduction of the negative acquisition adjustment. Additionally, the amortization of the acquisition adjustment should be reduced by $5,722 for water and $274 for wastewater to recognize the non-used and useful portion of the acquisition adjustment. The total adjustment to the Utility's amortization expense is a reduction of $9,660 for water and $3,456 for wastewater.

Issue 15: Should any adjustments be made to taxes other than income taxes (TOTI)?

Recommendation: Yes. Taxes other than income taxes should be decreased $6,740 for water and increased $1,703 for wastewater. (Cicchetti, Archer)

Staff Analysis: Taxes other than income taxes have been reduced by staff in the amount of $4,736 for water and increased by $1,995 for wastewater to reflect the revenue adjustments cited above. The balances of TOTI were also decreased by $2,042 for water and by $292 for wastewater to reflect changes to non-used and useful plant. Finally, the balance was increased by $38 for water to reflect property tax on the additional pro-forma plant.

The net impact of the recommended adjustments results in a decrease to the balance of TOTI of $6,740 for water and an increase of $1,703 for wastewater.

Issue 16: What is the appropriate amount of rate case expense for the current case?

Recommendation: The appropriate amount of rate case expense for the current case is $8,036. This represents rate case expense of $6,091 for water and $1,945 for wastewater. Amortized over 4 years, this represents an annual rate case expense of $1,522 for water and $486 for wastewater. As a result, staff has increased annual rate case expense for water by $216 and for wastewater by $69. (Cicchetti, Archer)

Staff Analysis: The Utility originally requested $6,895 of estimated rate case expense. This amount included the Utility's filing fee, notices for the customer meeting and for final rates, and travel costs to attend the Agenda Conference. The Utility subsequently requested an additional $1,141 and has provided invoices for the amounts already incurred. Staff believes the amount of rate case expense requested is reasonable and has included these amounts in the recommended total rate case expense. The following table shows the Utility's requested rate case expense:

Table 13
Rate Case Expense

Description	MFR B-10	Additional Request	Revised Total
Notice-Customer Meeting	$972	$11	$983
Notice-Final Rates	$972	$11	$983
Travel-customer Meeting	$225	$538	$763
Filing Fee	$4,500		$4,500
Travel-PAA Agenda	$225	$582	$807
Total	$6,895	$1,141	$8,036

In summary, the appropriate amount of rate case expense for the current case is $8,036. This represents rate case expense of $6,091 for water and $1,945 for wastewater. Amortized over 4 years, this represents an annual rate case expense of $1,522 for water and $486 for wastewater.

Issue 17: What is the appropriate amount of bad debt expense for the test year ending June 30, 2014?

Recommendation: The appropriate amount of bad debt expense is $7,434 for water and $2,047 for wastewater. Test year bad debt expense should be reduced by $6,295 for water and increased by $1,656 for wastewater. (Cicchetti, Archer)

Staff Analysis: In its letter of concerns dated March 13, 2015, regarding bad debt expense as a percentage of revenue, OPC stated it is:

> "...concerned that the requested 2.55% for water is unreasonable and unsupported." OPC went on to say it also "...has concerns with the Company's use of one data point in time to support its bad debt write-offs. The Commission historically uses a 3 to 5 year average of bad debts expense to use for prospective rates. While we recognize that the test year was the first year of operation for the new owner, another year has almost passed since the purchase. Since HCWW has only had two years of operating experience, OPC would like to see what has happened in the most recent twelve months regarding bad debt expense and write-offs."

On March 17, 2015, the Utility responded to OPC's letter of concerns. In its response, the Utility stated, "HC Waterworks now records Bad Debt Expense monthly based on its actual Aged Accounts Receivable report for balances over 60-days." The Utility further stated "that in the last rate case for these systems, the Commission approved a bad debt expense of 1.67%." Finally, the Utility reported in its letter of response "HC Waterworks bad debt for its first full year of operation ending December 31, 2014 was 1.69%."

The Commission's practice is to allow the most recent three-year average for bad debt expense. Because the Utility has less than two-years of actual operating experience this is not possible. Staff believes the Utility's most recent full year experience for bad debt expense of 1.69 percent of revenues is reasonable. The 1.69 percent of revenues compares favorably to the 1.67 percent the Commission allowed for this Utility in its last rate case.[7] Staff has decreased bad debt expense $6,295 for water and increased bad debt expense $1,656 for wastewater to reflect bad debt expense based on 1.69 percent of test year revenues. Staff recommends the appropriate amount of bad debt expense is $7,434 for water and $2,047 for wastewater.

[7] Order No. PSC-12-0102-FOF-WS, issued March 5, 2012, in Docket No. 100300-WS, In re: Application for increase in water/wastewater rates in Alachua, Brevard, Desoto, Hardee, Highlands, Lake, Lee, Marion, Orange, Palm Beach, Pasco, Polk, Putnam, Seminole, Sumter, Volusia, and Washington Counties by Aqua Utilities, Florida, Inc.

REVENUE REQUIREMENT

Issue 18: What is the appropriate revenue requirement for water and wastewater?

Recommendation: The following revenue requirement should be approved:

Table 18
Revenue Requirement

	Test Year Revenue	$ Increase/(Decrease)	Revenue Requirement	Percentage Increase/(Decrease)
Water	$439,875	$97,731	$537,606	22.22%
Wastewater	$121,100	($35,921)	$85,178	(29.66%)

(Cicchetti, Archer)

Staff Analysis: In its revised filing, the Utility requested revenue requirements to generate annual revenue of $545,113 for water and $76,774 for wastewater. These requested revenue requirements represent an increase of 37.78 percent for water and a decrease of 36.63 percent for wastewater. Consistent with staff's recommendations concerning rate base, the cost of capital, and net operating income, staff recommends approval of rates designed to generate revenue requirements of $537,606 for water and $85,178 for wastewater. The recommended revenue requirements represent an increase of $97,731, or 22.22 percent, for water and a decrease of $35,921, or 29.66, percent for wastewater. The recommended revenue requirements will allow the Utility the opportunity to recover its expenses and earn an overall rate of return of 7.79 percent on its investment in rate base. The computations of the revenue requirements are shown on Schedule Nos. 3-A and 3-B and staff adjustments to net operating income are shown on Schedule No. 3-C.

RATES

Issue 19: What are the appropriate rate structures and rates for HC's water and wastewater systems? (Bruce)

Recommendation: The recommended rate structures and monthly water and wastewater rates are shown on Schedule Nos. 4-A through 4-D. 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. (Bruce)

Staff Analysis:

Water Rates

HC is located in Highlands County within the Southwest Florida Water Management District. The Utility provides water service to approximately 923 residential water customers in 3 subdivisions and 6 general service customers. One of the general service customers is a 189 unit RV park. Approximately 25 percent of the residential customer bills during the test year had zero gallons, indicating a seasonal customer base. The average residential water demand is 2,520 gallons per month. The average water demand excluding zero gallon bills is 3,343 per month. The Utility's current water system rate structure for residential customers consists of a base facility charge (BFC) and three-tier inclining block rate structure. The rate blocks are: (1) 0-6,000 gallons; (2) 6,001-12,000 gallons; and (3) all usage in excess of 12,000 gallons per month. General service customers are billed based on a BFC and uniform gallonage charge. This rate structure was approved in the Utility's last rate case prior to the transfer from Aqua to HC.

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.

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. In the Utility's last rate case, a BFC allocation of 40 percent was approved. However, due to the customers' 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 person 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 74 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. Although the Utility does not have customers for residential irrigation and private fire protection, the Utility would like to maintain a rate structure for these customer classes in the event they are needed in the future. Staff recommends that the residential irrigation rate structure and rates be the same as the residential water customers. The private fire protection rate should be one-twelfth of the approved BFC, pursuant to Rule 25-30.465, F.A.C. General service customers should be billed a BFC and uniform gallonage charge.

Furthermore, staff evaluated whether a BFC for the RV park should be based on a three-inch meter, 16 equivalent residential connections (ERCs), or the demand the RV park places on the water system. During the test year, the RV park use 2,270,000 gallons of water. Compared with the average residential water demand of 2,520 gallons per month, the RV park demand represents approximately 75 ERCs (2,270,000/2,520/12) Therefore, staff recommends a BFC based on 75 ERCs for the RV park and a uniform gallonage charge.

In addition, based on a recommended revenue increase of approximately 23 percent, excluding miscellaneous revenues, the residential consumption can be expected to decline by 1,150,000 gallons resulting in anticipated average residential demand of 2,417 gallons per month. Staff recommends a 4.10 percent reduction in total residential consumption and corresponding reductions of $1,939 for purchased power, $1,361 for chemicals, and $155 for RAFs to reflect the anticipated repression, which results in a post repression revenue requirement of $519,008. 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 allocation based on 50 percent of the water revenue requirement. Staff also recommends a BFC based on 75 ERCs for the RV park. Staff recommends that the residential irrigation rate structure and rates be the same as the residential water customers. The private fire protection rate should be one-twelfth of the approved BFC, pursuant to Rule 25-30.465, F.A.C. General service customers should be billed a BFC and uniform gallonage charge. Staff's recommended rate structure and rates are shown on Schedule Nos. 4-A and 4-B.

Wastewater Rates

HC provided wastewater service to 297 residential customers in the Leisure Lakes development. Currently, the residential wastewater rate structure consists of a uniform BFC for all meter sizes and a gallonage charge with a 6,000 gallon cap per month. The general service rate includes a BFC by 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.

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. As mentioned earlier, the customer base is seasonal; therefore, 50 percent of the wastewater revenue should be allocated to the BFC. It is Commission practice to set the wastewater cap at approximately 80 percent of residential water sold. Based on staff's review of the billing analysis, 96 percent of the gallons are captured at the 6,000 gallon consumption level. The wastewater gallonage cap recognizes that not all water used by the residential customers is returned to the wastewater system. For this reason, staff recommends that the gallonage cap of 6,000 per month remain unchanged. Staff recommends that the general service gallonage charge be 1.2 times greater than the residential gallonage charge which is consistent with Commission practice. Although, the Utility does not have any wastewater-only customers, HC would like to establish a flat rate for this customer class. The flat rate for wastewater only should be based on the residential BFC and the average residential water demand for the wastewater customers (1,565 gallons) times the residential gallonage charge.

In addition, based on the expected reduction in water demand described above, staff recommends that a repression adjustment also be made for wastewater. Because wastewater rates are calculated based on customers' water demand, if those customers' water demand is expected to decline, then the billing determinants used to calculate wastewater rates should also be adjusted. Therefore, staff recommends that a repression adjustment should also be made to calculate wastewater rates. Based on the billing analysis for the wastewater system, staff recommends a repression adjustment of 67,096 gallons to reflect the anticipated reduction in water demand used to calculate wastewater rates. Staff recommends a 13.26 percent reduction in total residential consumption and corresponding reductions of $46 for purchased power, $35 for chemicals, $45 for sludge removal, and $6 for RAFs to reflect the anticipated repression, which results in a post repression revenue requirement of $85,046. Staff recommends a BFC based on an allocation of 50 percent of the wastewater revenue requirement and no change to the wastewater gallonage cap of 6,000 gallons. 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. Staff's recommended rate structure and rates are shown on Schedule Nos. 4-C and 4-D.

Summary

Based on the foregoing, the recommended rate structures and monthly water and wastewater rates are shown on Schedule Nos. 4-A through 4-D. 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.

OTHER ISSUES

Issue 20: What are 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 water and wastewater rates should be reduced as shown on Schedule Nos. 4-A and 4-B, to remove rate case expense grossed-up for regulatory assessment fees (RAFs) 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. HC 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. (Bruce, Cicchetti)

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 $1,610 for water and $514 for wastewater. Using HC's current revenue, expenses, capital structure and customer base, the reduction in revenue will result in the rate decreases as shown on Schedule Nos. 4-A and 4-B.

The Utility should be required to file revised tariff sheets no later than one month prior to the actual date of the required rate reduction. HC should also be required to file a proposed customer notice setting forth the lower rates and the reason for the 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 21: What are the appropriate customer deposits for HC's water and wastewater systems?

Recommendation: The appropriate initial customer deposits should be $99 and $50 for the residential 5/8 inch x 3/4 inch meter size for water and wastewater, respectively. 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 water and wastewater. The approved initial 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 collect the approved deposits until authorized to change them by the Commission in a subsequent proceeding. (Bruce)

Staff Analysis: Rule 25-30.311, F.A.C., provides 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. An initial customer deposit ensures that the cost of providing service is recovered from the cost causer. Historically, the Commission has set initial customer deposits equal to two times the average estimated bill.[8] Currently, the Utility's initial deposits are $89 for water and $105 for wastewater. Based on the staff recommended rates, the appropriate initial customer deposit should be $99 for water and $50 for wastewater to reflect an average residential customer bill for two months.

Staff recommends the appropriate initial customer deposits should be $99 and $50 for the residential 5/8 inch x 3/4 inch meter size for water and wastewater, respectively. 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 water and wastewater. The approved initial 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 collect the approved deposits until authorized to change them by the Commission in a subsequent proceeding.

[8] See Order No. PSC-15-0142-PAA-SU, issued March 26, 2015, in Docket No. 130178-SU, In re: Application for staff-assisted rate case in Polk County by Crooked Lake Park Sewerage Company.

Issue 22: Should the Utility be required to provide proof, within 90 days of the final order in this docket, that it has adjusted its books for all applicable National Association of Regulatory Commissioners Uniform System of Accounts (NARUC USOA) primary accounts associated with the Commission approved adjustments?

Recommendation: Yes. To ensure that the Utility adjusts its books in accordance with the Commission's decision, HC should provide proof, within 90 days of the final order in this docket, that the adjustments for all applicable NARUC USOA primary accounts have been made. (Cicchetti)

Staff Analysis: To ensure that the Utility adjusts its books in accordance with the Commission's decision, HC should provide proof, within 90 days of the final order in this docket, that the adjustments for all applicable NARUC USOA primary accounts have been made.

Issue 23: Should this docket be closed?

Recommendation: No. If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the order, a consummating order should be issued. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff, and that the adjustments for all applicable NARUC USOA primary accounts have been made. Once these actions are complete, this docket should be closed administratively. (Mapp, Crawford)

Staff Analysis: If no person whose substantial interests are affected by the proposed agency action files a protest within 21 days of the issuance of the order, a consummating order should be issued. The docket should remain open for staff's verification that the revised tariff sheets and customer notice have been filed by the Utility and approved by staff, and that the adjustments for all applicable NARUC USOA primary accounts have been made. Once these actions are complete, this docket should be closed administratively.

HC Waterworks, Inc.
Schedule of Water Rate Base
Test Year Ended 06/30/14

Schedule No. 1-A
Docket No. 140158-WS

	Description	Test Year Per Utility	Utility Adjust-ments	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year
1.	Plant in Service	$3,722,490	$38,451	$3,760,941	$4,342	$3,765,283
2.	Land and Land Rights	25,450	0	25,450	0	25,450
3.	Less: Non-used and Useful Components	0	(83,999)	(83,999)	(92,788)	(176,787)
4.	Construction Work in Progress	0	0	0	0	0
5.	Less: Accumulated Depreciation	(695,456)	17,280	(678,176)	(31,165)	(709,341)
6.	Less: CIAC	(841,545)	0	(841,545)	(500)	(842,045)
7.	Accumulated Amortization of CIAC	469,066	0	469,066	0	469,066
8.	Acquisition Adjustments	0	(849,440)	(849,440)	40,399	(809,041)
9.	Less: Accum. Amort. Of Acq. Adjustments	0	78,581	78,581	(3,937)	74,644
10.	Less: Advances for Construction	0	0	0	0	0
11.	Working Capital Allowance	0	38,268	38,268	338	38,606
12.	**Rate Base**	$2,680,005	($760,859)	$1,919,146	($83,311)	$1,835,835

HC Waterworks, Inc.
Schedule of Wastewater Rate Base
Test Year Ended 06/30/14

Schedule No. 1-B
Docket No. 140158-WS

	Description	Test Year Per Utility	Utility Adjust-ments	Adjusted Test Year Per Utility	Staff Adjust-ments	Staff Adjusted Test Year
1.	Plant in Service	$385,287	$0	$385,287	$52	$385,339
2.	Land and Land Rights	2,200	0	2,200	0	2,200
3.	Less: Non-used and Useful Components	0	(7,174)	(7,174)	(135)	(7,309)
4.	Construction Work in Progress	0	0	0	0	0
5.	Less: Accumulated Depreciation	(282,952)	0	(282,952)	(6,024)	(288,976)
6.	Less: CIAC	(285,550)	0	(285,550)	0	(285,550)
7.	Accumulated Amortization of CIAC	240,663	0	240,663	0	240,663
8.	Acquisition Adjustments	0	(21,078)	(21,078)	6,048	(15,030)
9.	Less: Accum. Amort. Of Acq. Adjustments	0	4,569	4,569	(3,182)	1,387
10.	Less: Advances for Construction	0	0	0	0	0
11.	Working Capital Allowance	0	9,495	9,495	(63)	9,432
12.	**Rate Base**	$59,648	($14,188)	$45,460	($3,304)	$42,156

HC Waterworks, Inc. Adjustments to Rate Base Test Year Ended 06/30/14		Schedule No. 1-C Docket No. 140158-WS
Explanation	**Water**	**Wastewater**
Plant In Service		
1. Per Audit Finding 1	$1,546	$52
2. Per Audit Finding 3 - Additional Items	$11,643	$0
3. Retirement on meter replacements to Acct. No. 334	($986)	
4. Retirement on additional item added to Acct. No. 310.2	($7,862)	
Total	$4,342	$52
Non-used and Useful		
To reflect net non-used and useful adjustment	($92,788)	($135)
Accumulated Depreciation		
1. Per Audit Finding 1	$969	$0
2. Per Audit Finding 2	$0	$24
3. Depreciation Pro-Forma Audit Items	$7,279	$0
4. Retirement on meter replacements to Acct. No. 334	$986	
5. Stranded Asset- Negative Accumulated Depreciation	($40,399)	($6,048)
Total	($31,165)	($6,024)
CIAC		
Per Audit Finding 4 - Water	($500)	$0
Acquisition Adjustment		
To reflect removal of stranded asset from acq adj	$40,399	$6,048
Accumulated Amortization of Acq. Adj.		
Per Audit	(3,937)	(3,182)
Working Capital		
To reflect working capital	$338	($63)

HC Waterworks, Inc.
Capital Structure-Simple Average
Test Year Ended 06/30/14

Schedule No. 2
Docket No. 140158-WS

	Description	Total Capital	Specific Adjust-ments	Subtotal Adjusted Capital	Prorata Adjust-ments	Capital Reconciled to Rate Base	Ratio	Cost Rate	Weighted Cost
Per Utility									
1	Long-term Debt	$818,881	$0	$818,881	($267,315)	$551,566	32.41%	4.25%	1.38%
2	Short-term Debt	0	0	0	0	0	0.00%	0.00%	0.00%
3	Preferred Stock	0	0	0	0	0	0.00%	0.00%	0.00%
4	Common Equity	1,699,426	0	1,699,426	(554,760)	1,144,666	67.25%	9.52%	6.40%
5	Customer Deposits	8,563	0	8,563	(2,795)	5,768	0.34%	2.00%	0.01%
6	Deferred Income Taxes	0	0	0	0	0	0.00%	0.00%	0.00%
7	**Total Capital**	$2,526,870	$0	$2,526,870	($824,870)	$1,702,000	100.00%		7.79%
Per Staff									
8	Long-term Debt	$818,881	$0	$818,881	($210,350)	$608,531	32.40%	4.25%	1.38%
9	Short-term Debt	0	0	0	0	0	0.00%	0.00%	0.00%
10	Preferred Stock	0	0	0	0	0	0.00%	0.00%	0.00%
11	Common Equity	1,699,426	0	1,699,426	(436,539)	1,262,887	67.25%	9.52%	6.40%
12	Customer Deposits	8,563	282	8,845	(2,272)	6,573	0.35%	2.00%	0.01%
13	Deferred Income Taxes	0	0	0	0	0	0.00%	0.00%	0.00%
14	**Total Capital**	$2,526,870	$282	$2,527,152	($649,161)	$1,877,991	100.00%		7.79%

	LOW	HIGH
RETURN ON EQUITY	8.52%	10.52%
OVERALL RATE OF RETURN	7.11%	8.46%

HC Waterworks, Inc.
Statement of Water Operations
Test Year Ended 06/30/14

Schedule No. 3-A
Docket No. 140158-WS

	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:**	$390,596	$154,517	$545,113	($105,238)	$439,875	$97,731 22.22%	$537,606
	Operating Expenses							
2.	Operation & Maintenance	$299,336	$9,737	$309,073	($226)	$308,847		$308,847
3.	Depreciation	95,608	5,370	100,977	(8,158)	92,819		92,819
4.	Amortization	0	(78,581)	(78,581)	9,660	(68,921)		(68,921)
5.	Taxes Other Than Income	59,409	4,858	64,266	(6,740)	57,526	4,398	61,924
6.	Income Taxes	0	0	0	0	0	0	0
7.	**Total Operating Expense**	454,352	(58,616)	395,735	(5,465)	390,270	4,398	394,668
8.	**Operating Income**	($63,755)	$213,133	$149,378	($99,773)	$49,605	$93,334	$142,939
9.	**Rate Base**	$2,680,005		$1,919,146		$1,835,835		$1,835,835
10.	**Rate of Return**	-2.38%		7.78%		2.70%		7.79%

HC Waterworks, Inc.
Statement of Wastewater Operations
Test Year Ended 06/30/14

Schedule No. 3-B
Docket No. 140158-WS

	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:**	$111,686	($34,911)	$76,775	$44,324	$121,099	($35,921) -29.66%	$85,178
	Operating Expenses							
2.	Operation & Maintenance	$79,399	($4,308)	$75,090	$364	$75,454		$75,454
3.	Depreciation	(372)	(2,553)	(2,925)	4,757	1,832		1,832
4.	Amortization	0	(4,569)	(4,569)	3,456	(1,113)		(1,113)
5.	Taxes Other Than Income	8,903	(3,266)	5,637	1,703	7,340	(1,616)	5,723
6.	Income Taxes	0	0	0	0	0	0	0
7.	**Total Operating Expense**	87,930	(14,696)	73,234	10,280	83,513	(1,616)	81,896
8.	**Operating Income**	$23,755	($20,215)	$3,540	$34,044	$37,586	($34,304)	$3,282
9.	**Rate Base**	$59,648		$45,460		$42,156		$42,156
10.	**Rate of Return**	39.83%		7.79%		89.16%		7.79%

HC Waterworks, Inc. Adjustment to Operating Income Test Year Ended 06/30/14		Schedule No. 3-C Docket No. 140158-WS
Explanation	**Water**	**Wastewater**
Operating Revenues		
1. Remove requested final revenue increase	($149,459)	$44,371
2. To reflect appropriate test year operating revenues	$44,221	($47)
Total	($105,238)	$44,324
Operation and Maintenance Expense		
1. Additional Rate case expense	$216	$69
2. To reflect I&I adjustment to purchased power and chemicals	$0	($565)
3. To reflect appropriate bad debt expense	($6,295)	$1,656
4. To reflect appropriate administrative cost for salaries	($999)	($306)
5. To reflect appropriate administrative cost for fuel	($1,379)	($422)
6. To reflect appropriate admin. cost for vehicle maintenance	($222)	($68)
7. To reflect increased chemicals for chloramine conversion	$8,452	$0
Total	($226)	$364
Depreciation Expense - Net		
1. Per Audit Finding 1	$36	$0
2. Per Audit Finding 2	$0	$357
3. Per Audit Finding 3 - Additional Items	$58	$0
4. Per Audit Finding 9 - Amortization of CIAC Expense	$0	$4,568
5. To remove non-U&U depreciation expense.	($8,252)	($168)
Total	($8,158)	$4,757
Amortization Expense		
1. Amortization Acq. Expense	$3,938	$3,182
2. To reflect non U&U amort of acquisition adj exp	$5,722	$274
Total	$9,660	$3,456
Taxes Other Than Income		
1. To reflect RAFs for revenue adjustments above.	($4,736)	$1,995
2. To reflect property tax on non-used and useful plant	($2,042)	($292)
3. Property Tax on Add. Pro-forma Plant	$38	$0
Total	($6,740)	$1,703

HC WATERWORKS, INC STAFF'S RECOMMENDED AND ALTERNATIVE WATER RATE STRUCTURES AND RATES				
Test Year Rate Structure and Rates			Recommended Rate Structure and Rates	
3-Tier Inclining Block Rate Structure BFC generated from current rates = 55%			Monthly BFC/ 2-Tier Rate Structure BFC = 50%	
BFC	$18.92		BFC	$21.49
0-6 kgals	$6.46		0-3 kgals (non-discretionary)	$8.32
6+-12 kgals	$9.71		Over 3 kgals	$10.40
12+ kgals	$12.93			
Typical Monthly Bills			Typical Monthly Bills	
Consumption (kgals)			Consumption (kgals)	
0	$18.92		0	$21.49
1	$25.38		1	$29.81
3	$38.30		3	$46.45
6	$57.68		6	$77.65
10	$96.52		10	$119.25
20	$219.38		20	$223.25
Alternative 1 Rate Structure and Rates			Alternative 2 Rate Structure and Rates	
Monthly BFC/2-Tier Rate Structure BFC = 55%			Monthly BFC/2-Tier Rate Structure BFC =40%	
BFC	$23.67		BFC	$17.15
0-3 kgals (non-discretionary)	$7.43		0-3 kgals (non-discretionary)	$10.14
Over 3 kgals	$9.29		Over 3 kgals	$12.67
Typical Monthly Bills			Typical Monthly Bills	
Consumption (kgals)			Consumption (kgals)	
0	$23.67		0	$17.15
1	$31.10		1	$27.29
3	$45.96		3	$47.57
6	$73.83		6	$85.58
10	$110.99		10	$136.26
20	$203.89		20	$262.96

HC Waterworks, Inc.
Docket No. 140158-WS
Monthly Water Rates

Schedule No. 4-B
Docket No. 140158-WS
Page 1 OF 2

	Utility Current Rates	Utility Requested Rates	Staff Recommended Rates	4 Year Rate Reduction
Residential and General Service				
Base Facility Charge by Meter Size				
5/8"X3/4"	$18.92	$23.42	$21.49	$0.07
3/4"	$28.38	$35.14	$32.24	$0.10
1"	$47.31	$58.56	$53.73	$0.17
1-1/2"	$94.61	$117.12	$107.45	$0.33
2"	$151.38	$187.39	$171.92	$0.53
3"	$302.77	$374.78	$343.84	$1.07
4"	$473.07	$585.60	$537.25	$1.67
6"	$946.15	$1,171.20	$1,074.50	$3.33
8"	$1,513.83	$1,873.92	$1,719.20	$5.33
10"	$2,176.13	$2,693.76	$2,471.35	$7.66
Charge per 1,000 Gallons - Residential				
0-6,000 gallons	$6.46	$8.21		
6,001-12,000 gallons	$9.71	$12.31		
Over 12,000 gallons	$12.93	$16.41		
0-3,000 gallons			$8.32	$0.03
Over 3,000 gallons			$10.40	$0.03
Charge per 1,000 Gallons - General Service	$7.25	$8.79	$8.91	$0.03

HC Waterworks, Inc. Docket No. 140158-WS Monthly Water Rates				Schedule No. 4-B Docket No. 140158-WS Page 2 OF 2
	Utility Current Rates	Utility Requested Rates	Staff Recommended Rates	4 Year Rate Reduction
Irrigation				
Base Facility Charge by Meter Size				
5/8"X3/4"	$18.92	$23.42	$21.49	$0.07
3/4"	$28.38	$35.14	$32.24	$0.10
1"	$47.31	$58.56	$53.73	$0.17
1-1/2"	$94.61	$117.12	$107.45	$0.33
2"	$151.38	$187.39	$171.92	$0.53
3"	$302.77	$374.78	$343.84	$1.07
4"	$473.07	$585.60	$537.25	$1.67
Charge per 1,000 Gallons				
0-6,000 gallons	$6.46	$8.21		
6,001-12,000 gallons	$9.71	$12.31		
Over 12,000 gallons	$12.93	$16.41		
0-3,000 gallons			$8.32	$0.03
Over 3,000 gallons			$10.40	$0.03
Private Fire Protection				
2"	$12.62	$15.62	$14.33	$0.04
3"	$25.23	$31.23	$28.65	$0.09
4"	$39.43	$48.80	$44.77	$0.14
6"	$78.85	$97.60	$89.54	$0.28
8"	$126.16	$156.16	$143.27	$0.44
10"	$181.34	$224.48	$205.95	$0.64
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
3,000 Gallons	$38.30	$48.05	$46.45	
6,000 Gallons	$57.68	$72.68	$77.65	
8,000 Gallons	$77.10	$97.30	$98.45	

HC WATERWORKS, INC. STAFF'S RECOMMENDED AND ALTERNATIVE WASTEWATER RATE STRUCTURES AND RATES				
Test Year Rate Structure and Rates			Recommended Rate Structure and Rates	
Monthly BFC/Uniform Gallonage Rate Structure BFC generated from current rates = 66%			Monthly BFC/Uniform Gallonage Rate Structure BFC = 50%	
BFC	$22.59		BFC	$12.00
per 1 kgal	$7.64		per 1 kgal	$8.03
(6 kgal cap)			(6 kgal cap)	
Typical Monthly Bills			Typical Monthly Bills	
Consumption (kgals)			Consumption (kgals)	
0	$22.59		0	$12.00
1	$30.23		1	$20.03
2	$37.87		2	$28.06
3	$45.51		3	$36.09
4	$53.15		4	$44.12
5	$60.79		5	$52.15
6	$68.43		6	$60.18
10	$68.43		10	$60.18
Alternative 1 Rate Structure and Rates			Alternative 2 Rate Structure and Rates	
Monthly BFC/Uniform Gallonage Rate Structure BFC = 55%			Monthly BFC/Uniform Gallonage Rate Structure BFC =45%	
BFC	$13.20		BFC	$10.80
per 1 kgal	$7.22		per 1 kgal	$8.83
(6 kgal cap)			(6 kgal cap)	
Typical Monthly Bills			Typical Monthly Bills	
Consumption (kgals)			Consumption (kgals)	
0	$13.20		0	$10.80
1	$20.42		1	$19.63
2	$27.64		2	$28.46
3	$34.86		3	$37.29
4	$42.08		4	$46.12
5	$49.30		5	$54.95
6	$56.52		6	$63.78
10	$56.52		10	$63.78

HC Waterworks, Inc. **Docket No. 140158-WS** **Monthly Wastewater Rates**				**Schedule No. 4-D** **Docket No. 140158-WS**
	Utility Current Rates	**Utility Requested Rates**	**Staff Recommended Rates**	**4 Year Rate Reduction**
Residential				
Base Facility Charge - All Meter Sizes	$22.59	$15.14	$12.00	$0.07
Charge per 1,000 Gallons 6,000 gallon cap	$7.64	$4.30	$8.03	$0.05
Flat Rate		$21.88	$24.57	$0.15
General Service				
Base Facility Charge by Meter Size				
5/8"X3/4"	$22.59	$15.14	$12.00	$0.07
3/4"	$33.90	$22.71	$18.00	$0.11
1"	$56.50	$37.86	$30.00	$0.18
1-1/2"	$112.98	$75.71	$60.00	$0.36
2"	$180.78	$121.14	$96.00	$0.58
3"	$361.54	$242.28	$192.00	$1.15
4"	$564.91	$378.56	$300.00	$1.80
6"	$1,129.83	$757.12	$600.00	$3.60
8"	$1,807.20	$1,211.40	$960.00	$5.76
10"	$2,598.61	$1,741.39	$1,380.00	$8.28
Charge per 1,000 Gallons	$9.16	$5.16	$9.63	$0.06
Typical Residential 5/8" x 3/4" Meter Bill Comparison				
3,000 Gallons	$45.51	$26.87	$36.09	
6,000 Gallons	$68.43	$39.23	$60.18	
8,000 Gallons	$68.43	$39.23	$60.18	

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: June 4, 2015

TO: Office of Commission Clerk (Stauffer)

FROM: Office of Industry Development and Market Analysis (Crawford)
Office of the General Counsel (Ames)

RE: Docket No. 150099-EI – Petition for approval of revised net metering tariff and agreement adopting terms of standard interconnection agreement for Tier 1, Tier 2, or Tier 3 renewable generator systems, by Tampa Electric Company.

AGENDA: 06/18/15 – Regular Agenda – Tariff Filling- Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: Company Waived 60-Day Suspension Date until 6/19/2015

SPECIAL INSTRUCTIONS: None

Case Background

On March 27, 2015, Tampa Electric Company (TECO) filed a petition for approval of revisions to the net metering tariff and agreement adopting terms of the standard interconnection agreement (SIA) for Tier 1, Tier 2, and Tier 3 renewable generator systems. In its petition, TECO seeks approval of a modification to its Net Metering Tariff (NM-1) and an associated new agreement that facilitates the adoption of the terms, conditions, and obligations of an existing SIA by tenants who lease premises with pre-existing customer owned renewable generator facilities installed by the property owner. Following the filing of the petition, staff held two informal meetings between staff, the utility, and interested persons to the docket.[1] During the

[1] Document No. 02087-15, April 14, 2015, Notice of Informal Meeting between Commission staff and interested persons to Docket No. 150099-EI, and Document No. 02849-15, May 14, 2015, Notice of Informal Meeting between Commission Staff and interested persons to docket No. 150099-EI.

including identifying specific provisions of the pre-existing SIA which the tenant would be responsible for and additional clarifying language related to consequences of property owners' failure to abide by all of its commitments under the pre-existing SIA between the property owner and TECO. On May 27, 2015, TECO filed a supplement to its petition incorporating changes discussed during the May 21, 2015 meeting.[2] On May 22, 2015 TECO by letter waived the sixty day file and suspend period with respect to this docket.

The Commission has jurisdiction over this matter pursuant to Sections 366.06 Florida Statutes (F.S.).

[2] Document No. 03328-15, June 3, 2015, letter waiving the sixty day file and suspend period until June 19, 2015, with respect to the revised net metering tariff and agreement proposed in Docket No. 150099-EI.

Discussion of Issues

Issue 1: Should TECO's petition for the approval of its revised net metering tariff and agreement adopting terms of the SIA for Tier 1, Tier 2, or Tier 3 renewable generator systems be suspended pending a final decision in this docket?

Recommendation: Yes. The revised net metering tariff and agreement adopting terms of the SIA for Tier 1, Tier 2, or Tier 3 renewable generator systems should be suspended pending final decision in this docket. (Ames, B. Crawford)

Staff Analysis: TECO filed its petition on March 27, 2015 seeking approval of its revised net metering tariff and agreement adopting terms of the SIA for Tier 1, Tier 2, or Tier 3 renewable generator systems

The suspension of the rate increase is authorized by Section 366.06(3), F.S., which provides:

> Pending a final order by the commission in any rate proceeding under this section, the commission may withhold consent to the operation of all or any portion of the new rate schedules, delivering to the utility requesting such increase, within 60 days, a reason or written statement of good cause for withholding its consent.

Staff recommends that the Commission suspend TECO's request for approval of its revised net metering tariff and agreement adopting terms of the SIA for Tier 1, Tier 2, or Tier 3 renewable generator systems. Suspending the tariff will allow staff adequate time to thoroughly review the petition and issue a fully informed recommendation for the Commission's review. Staff believes that this reason constitutes good cause consistent with the requirement of Section 366.06(3), F.S.

Issue 2: Should this docket be closed?

Recommendation: No. The docket should remain open to allow staff adequate time to review the filing and bring a recommendation back to the Commission on the merits of the filing. (Ames)

Staff Analysis: The docket should remain open pending the Commission's final decision on the revised net metering tariff and agreement adopting terms of the SIA for Tier 1, Tier 2, or Tier 3 renewable generator systems.