I. Meeting Packet



State of Florida Public Service Commission INTERNAL AFFAIRS AGENDA

Tuesday, November 29, 2016 Following Special Commission Agenda Room 105 - Gerald L. Gunter Building

- 1. "Update from the Federal Communications Commission" by The Honorable Mignon Clyburn, FCC Commissioner
- 2. Draft Review of the 2016 Telecommunications Regulatory Assessment Fee Report (Attachment 1)
- Draft Review of the 2016 Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act (Attachment 2)
- 4. Draft Review of the 2016 Lifeline Report to the Legislature (Attachment 3)
- 5. Draft Review of the 2016 Ten-Year Site Plans for Florida's Electric Utilities (Attachment 4)
- 6. General Counsel's Report
- 7. Executive Director's Report
- 8. Other Matters

BB/ks

OUTSIDE PERSONS WISHING TO ADDRESS THE COMMISSION ON ANY OF THE AGENDAED ITEMS SHOULD CONTACT THE OFFICE OF THE EXECUTIVE DIRECTOR AT (850) 413-6463.

Attachment 1



Public Service Commission

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

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

DATE: November 18, 2016

- **TO:** Braulio L. Baez, Executive Director
- **FROM:** Beth W. Salak, Director, Office of Telecommunications Mark Long, Public Utilities Supervisor, Office of Telecommunications
- **RE:** Draft Review of the 2016 Regulatory Assessment Fee Report

Critical Information: ACTION IS NEEDED - Please place on the November 29, 2016, Internal Affairs agenda. **Commission approval of the Regulatory Assessment Fee Report draft is sought.** The 2016 Report is due to the Governor, the President of the Senate, and the Speaker of the House of Representatives, by January 15, 2017.

Pursuant to Section 364.336(3), Florida Statutes, "(b)y January 15, 2012, and annually thereafter, the commission must report to the Governor, the President of the Senate, and the Speaker of the House of Representatives, providing a detailed description of its efforts to reduce the regulatory assessment fee for telecommunications companies, including a detailed description of the regulatory activities that are no longer required; the commensurate reduction in costs associated with this reduction in regulation; the regulatory activities that continue to be required under this chapter; and the costs associated with those regulatory activities."

The draft report includes a staff-written synopsis of what actions the Commission has taken in 2016 to comply with the statutory requirements. Staff is requesting approval of the draft report.

Attachment cc: Mark Futrell, Deputy Executive Director, Technical

REPORT ON THE EFFORTS OF THE FLORIDA PUBLIC SERVICE COMMISSION TO REDUCE THE REGULATORY ASSESSMENT FEE FOR TELECOMMUNICATIONS COMPANIES



As of December 2016

REPORT ON THE EFFORTS OF THE FLORIDA PUBLIC SERVICE COMMISSION TO REDUCE THE REGULATORY ASSESSMENT FEE FOR TELECOMMUNICATIONS COMPANIES



As of December 2016

Office of Telecommunications

Introduction

During the 2011 Legislative Session, House Bill CS/CS/HB 1231, the "Regulatory Reform Act" (Act), was passed and signed into law by the Governor, effective July 1, 2011. Under the Act, the Legislature eliminated most of the Florida Public Service Commission's (FPSC's or Commission's) retail oversight authority for the telecommunications wireline companies, yet maintained the FPSC's authority over wholesale intercarrier issues. The FPSC was required to reduce its regulatory assessment fees (RAFs) charged to wireline telecommunications companies to reflect the concurrent reduction in FPSC workload. Section 364.336(3), Florida Statutes, requires:

By January 15, 2012, and annually thereafter, the commission must report to the Governor, the President of the Senate, and the Speaker of the House of Representatives, providing a detailed description of its efforts to reduce the regulatory assessment fee for telecommunications companies, including a detailed description of the regulatory activities that are no longer required; the commensurate reduction in costs associated with this reduction in regulation; the regulatory activities that continue to be required under this chapter; and the costs associated with those regulatory activities.

As a result of this Act, the FPSC reduced its RAF rates 20%, from 0.0020 to 0.0016 of companies' gross operating revenues derived from intrastate business. This change became retroactively effective July 1, 2011. Florida telecommunications statutes have remained essentially unchanged since 2011. The FPSC has introduced numerous measures to streamline its telecommunications-related activities since that time, and continues to look for ways to streamline its remaining responsibilities.

Regulatory Activities That Are No Longer Required

The 2011 Act eliminated most of the retail regulation of local exchange telecommunications services by the FPSC, including the elimination of rate caps on all retail telecommunications services, elimination of telecommunications-related consumer protection and assistance duties of the FPSC, and elimination of the FPSC's remaining oversight of telecommunications service quality. The Act also reformed the FPSC's certification processes, authority over intercarrier matters, and other general revisions. Consistent with the reduced authority of the FPSC from the Act, the FPSC ceased the following activities over the past several years:

- Resolving non-basic retail consumer billing complaints.
- Addressing slamming or cramming complaints from consumers. The FPSC continues to address slamming complaints that are reported by carriers under the Commission's wholesale authority.
- Publishing and distributing materials informing consumers on billing-related matters or informative materials relating to the competitive telecommunications market.
- Designating wireless eligible telecommunications carriers (ETCs) in Florida for the federal universal service fund. Any wireless carrier seeking ETC status in Florida must petition the Federal Communications Commission (FCC) for that authority.
- Performing service evaluations on carriers, investigating and resolving service-related consumer complaints except as they may relate to Lifeline service, Telephone Relay Service, and payphones.
- Allowing ILECs to petition for recovery of storm-damage-related costs and expenses.
- Reviewing non-access service tariff filings for content, form, or format. It is the carrier's choice whether to file its rate schedules with the FPSC or publicly publish the schedules elsewhere, such as the companies' websites.

Savings

The FPSC has been seeking cost savings and efforts to streamline regulatory processes for well over a decade. The origin of these streamlining efforts is not limited to the emergence and evolution of competition in the telecommunications industry. In fiscal year 1999/2000, the FPSC had 401 full time positions. Through several reductions over a period of years, that number was reduced to 277 in the 2016/2017 fiscal year, a total reduction of 31 percent. Over the years, many of these reductions came as a result of projected workload reductions in the telecommunications area. At this time, the FPSC believes the Office of Telecommunications is right-sized for its current statutory obligations.

Effective July 2011, the FPSC reduced the telecommunications RAF rate from 0.0020 to 0.0016 of the gross operating revenues derived from intrastate business. In addition, all local telephone service

providers now pay \$600 as the minimum fee instead of varying rates based upon the service offered.¹ At the current 0.0016 rate, carriers will pay this minimum fee up to \$375,000 in gross intrastate The reduced RAF rate was determined assuming reduced responsibilities, operating revenues. projecting staff hours on continuing telecommunications workload, and projecting telecommunications company revenues. As they have for several years, revenues subject to RAF from the telecommunications companies regulated by the FPSC continued to decline in 2016 as traditional wireline revenues are replaced by unregulated (VoIP/broadband) services. Also, through consolidation of companies and the maturation of the markets, the number of regulated companies also continues to decline. Given all these factors, the agency is evaluating the need to further reduce the telecommunications RAF rate in 2017.

Regulatory Activities That Continue To Be Required

There were 331 telecommunications companies regulated in some way by the FPSC as of November 2, 2016. The Commission continues to retain authority and responsibility in the following areas for telecommunications companies:

- Resolving intercarrier disputes involving interpretations and implementation of sections of the intercarrier agreements.
- Processing arbitrations of intercarrier agreements when the companies cannot negotiate all the terms of the agreement and request the FPSC to resolve issues the companies define.
- Reviewing interconnection agreements filed with the FPSC in accordance with federal requirements.
- Resolving cases involving area code relief, number conservation plans, number resource reclamation, local number portability, and other numbering issues.
- Analyzing information for and producing several statutorily required reports: the Annual Report on the Status of the Telecommunications Access System Act of 1991, the Annual Report on Lifeline Assistance, the Report on the Efforts of the Florida Public Service Commission to Reduce the Regulatory Assessment Fee for Telecommunications Companies, and the Report on the Status of Competition in the Telecommunications Industry.
- Maintaining oversight of the Florida Relay Service.

¹ Previously, the minimum fee ranged from \$600 to \$1,000, depending on the type of service offered. Payphone operators continue to pay a minimum fee of \$100.

- Maintaining oversight of Florida's Lifeline Program, including establishing eligibility criteria, coordinated enrollment, and monitoring ETCs.
- Issuing certificates of authority for telecommunications companies to operate in Florida, including evaluating the applicant's technical, financial, and managerial capability to provide service.
- Resolving consumer complaints relating to Lifeline, Telephone Relay Service, and payphones.
- Publishing network access tariff information for all incumbent local carriers.
- Publishing other tariff/rate schedule information for any certificated company if the company so decides.
- Publishing and distributing informative materials relating to the Lifeline Program and conducts related consumer outreach.
- Monitoring and/or participating in federal proceedings in cases which the state's consumers may be affected and to convey the FPSC's positions and information requirements in order to achieve greater efficiency in regulation.

Efforts to Reduce Costs

The FPSC continues to find ways to reduce the costs of performing its continuing duties. In 2016, the FPSC continued its electronic tariff and service schedule publishing that will further reduce the number of paper documents at the agency. All official copies of telecommunications tariffs, price lists, and service schedules are available on the agency's website, as are all tariff updates. This development allows greater access to both consumers and companies and reduces costs associated with record requests. Additionally, the FPSC continues the process of eliminating all obsolete or redundant paper archives of companies' rates and schedules.

The telecommunications staff continues to conduct periodic internal cross training on its remaining responsibilities, through both scheduled office-wide training sessions and temporary transfers of job duties. It has also developed comprehensive written Standard Operating Procedures for its functions. As staff become familiar with each other's duties, the requisite training time will be reduced should the need arise to further consolidate or transfer functions. This proved valuable when all staff members in telecommunications were required to complete an arbitration request.

Summary

The FPSC continues to proactively respond to the changes in its statutory authority as a result of the Act. The agency has assessed the appropriate staffing levels for the telecommunications staff, and will continue to monitor the workload and staffing needs. The agency continues to seek ways to economize its resources while maintaining a high quality work product for all industries under the FPSC's authority, including telecommunications.

Attachment 2



Public Service Commission

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

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

DATE:	November 15, 2016
то:	Braulio Baez, Executive Director
FROM:	Robert Margolis, Public Utility Analyst II, Division of Economics MA So M Tripp Coston, Economic Supervisor, Division of Economics B South
RE:	Draft Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act (FEECA). Due March 1 to the Governor and Legislature.
	Critical Information: Please place on the November 29, 2016 Internal Affairs agenda. Commission approval is sought.

Section 366.82(10), Florida Statutes, requires the Commission to submit an annual report to the Governor and Legislature on utility progress towards meeting goals established by the Commission pursuant to the Florida Energy Efficiency and Conservation Act. The report is due by March 1 of each year.

Furthermore, Section 377.703(2)(f), F.S., requires the Commission to file information on electricity and natural gas energy conservation programs with the Department of Agriculture and Consumer Services.

Staff is seeking Commission approval of the attached draft report. Upon approval, the report will be submitted to the Governor, President of the Senate, Speaker of the House, and the Commissioner of Agriculture.

cc: Mark Futrell, Deputy Executive Director, Technical Apryl Lynn, Deputy Executive Director, Administrative Keith Hetrick, General Counsel



FLORIDA PUBLIC SERVICE COMMISSION

FEECA Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act

As Required by Sections 366.82(10), and 377.703(2)(f), Florida Statutes

DECEMBER 2016

Florida Public Service Commission

Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act

As Required by Sections 366.82(10) and 377.703(2)(f), Florida Statutes

December 2016

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List of Acronyms

С/І	Commercial and Industrial (Customers)			
DEF	Duke Energy Florida, LLC			
DOE	U.S. Department of Energy			
DR	Demand Response			
DSM	Demand-Side Management			
ECCR	Energy Conservation Cost Recovery Clause			
EE	Energy Efficiency			
EPA	U.S. Environmental Protection Agency			
F.A.C.	Florida Administrative Code			
FEECA	Florida Energy Efficiency and Conservation Act			
FIPUG	Florida Industrial Power Users Group			
FPL	Florida Power & Light Company			
FPSC	Florida Public Service Commission			
FPUC	Florida Public Utilities Company			
FRCC	Florida Reliability Coordinating Council			
F.S.	Florida Statutes			
GW	Gigawatt			
GWh	Gigawatt-Hour			
Gulf	Gulf Power Company			
HVAC	Heating, Ventilation and Air Conditioning			
IOU	Investor-owned Utility			
kWh	Kilowatt-Hour			
LDC	Natural Gas Local Distribution Company			
MW	Megawatt			
MWh	Megawatt-Hour			
OPC	Office of Public Counsel			
OUC	Orlando Utilities Commission			
O&M	Operations and Maintenance			
PV	Solar Photovoltaic			
RIM	Rate Impact Measure Test			
SACE	Southern Alliance for Clean Energy			
SEER	Seasonal Energy Efficiency Ratio			
TECO	Tampa Electric Company			
TRC	Total Resource Cost Test			

Executive Summary

Purpose

Reducing the growth of Florida's peak electric demand and energy consumption became a statutory objective in 1980, with the enactment of the Florida Energy Efficiency and Conservation Act (FEECA). Codified in Sections 366.80 through 366.83 and Section 403.519, Florida Statutes (F.S.), FEECA emphasizes reducing the growth rates of weather-sensitive peak electricity demand, reducing and controlling the growth rates of electricity consumption, and conserving expensive resources, particularly petroleum.

Section 366.82(2), F.S., requires the Florida Public Service Commission (FPSC or Commission) to set demand-side management (DSM) goals at least every five years for the seven electric utilities subject to FEECA. The Commission sets goals with respect to summer and winter electric peak demand and annual energy savings over a ten-year period, with a reevaluation review every five years. Once goals are established, the seven FEECA utilities must submit DSM plans containing cost-effective programs intended to meet the goals.

The seven electric utilities currently subject to FEECA are:

- Five Florida Investor-owned utilities (IOUs), ranked in order of sales
 - Florida Power & Light Company (FPL)
 - Duke Energy Florida, LLC (DEF)
 - o Tampa Electric Company (TECO)
 - o Gulf Power Company (Gulf)
 - Florida Public Utilities Company (FPUC)
- Two municipal utilities, ranked in order of sales
 - o JEA
 - Orlando Utilities Commission (OUC)

The Commission regulates the electric rates and energy conservation cost recovery of the five IOUs. In contrast, the Commission does not regulate the rates of the two municipal utilities for which it sets DSM goals.

The Commission is required by Section 366.82(10), F.S., to provide an annual report to the Florida Legislature and the Governor summarizing the adopted goals and progress toward achieving these goals. Similarly, Section 377.703(2)(f), F.S., requires the Commission to file information on electricity and natural gas energy conservation programs with the Department of Agriculture and Consumer Services. This report reviews the 2015 annual goal results for each FEECA utility and fulfills these statutory obligations.

Report Layout

This report presents the FEECA utilities' progress towards achieving the Commissionestablished goals and the Commission's efforts in overseeing these conservation initiatives. This report details these efforts through the following four sections and appendix:

- Section 1 provides a history of FEECA, highlights savings produced by utility programs since 2000, and provides a description of existing tools for increasing electricity and natural gas conservation throughout Florida.
- Section 2 discusses 2015 goals and achievements of the FEECA utilities.
- Section 3 provides an overview of Florida's electricity market.
- Section 4 discusses methods the Commission has used to educate consumers about conservation and provides a list of related web sites.
- Appendix 1 provides a list of the conservation programs currently offered by the FEECA utilities.

Pursuant to Section 366.82(10), F.S., this report on conservation results achieved by the FEECA utilities is due to the Florida Legislature and Governor by March 1, 2017.

2015 Achievements

The Commission has authority by statute to allow utilities to recover prudently incurred costs related to conservation.¹ The Commission has implemented this authority through the Energy Conservation Cost Recovery (ECCR) clause. The ECCR clause has been in existence since 1980. Since 1980, it is estimated that DSM programs offered by the FEECA utilities have reduced summer peak demand by 7,732 megawatts (MW) and winter peak demand by 7,263 MW. In comparison, the FEECA utilities currently have 46,584 MW of summer electric generating capacity and 50,227 MW of winter generating capacity. The history of FEECA and the ECCR clause are discussed in Section 1 of this report.

For 2015, Florida's investor-owned electric utilities recovered approximately \$382 million in conservation program expenditures. Florida's electric utilities also performed over 209,000 residential and commercial audits and offered 108 residential and commercial programs focused on energy conservation.

All seven FEECA utilities met the Commission's total DSM goals. Two Florida IOUs, TECO and Gulf, and one municipal utility, OUC, also met the Commission's energy and demand savings goals for the residential and commercial/industrial (C/I) customer classes. Three IOUs, FPL, DEF, and FPUC, and one municipal utility, JEA, did not meet every specific goal set by the Commission for the residential and C/I customer classes. Additional detail on each utility's performance is described in Section 2.

Goal Setting Process for the Current Period

On November 25, 2014, the Commission approved winter and summer peak demand and annual energy savings goals for the seven FEECA utilities for 2015 through 2024. The Commission approved goals based on the Rate Impact Measure (RIM) test to ensure that all ratepayers benefit from energy efficiency programs that pass the RIM test and thereby create a downward pressure

¹ Section 366.82(11), F.S.

on electric rates. The 2014 approved DSM goals for the FEECA utilities were lower than the goals approved by the Commission in 2009. The Commission identified fewer cost-effective energy efficiency programs as a result of more stringent building codes and appliance efficiency standards. The higher the current efficiency standards and codes, the less opportunity there is for utility-sponsored programs to be cost-effective. Additionally, lower utility avoided costs resulting from lower natural gas prices have contributed to fewer programs being cost-effective. The 2014 goal setting process is discussed further in Section 2.4.

Additionally, in November 2014, the Commission voted to allow the IOUs' five-year solar pilot programs to expire on December 31, 2015. The Commission based its decision on evidence in the record that the existing solar pilot programs were not cost-effective. Finally in 2014, the Commission mandated in its 2014 Goals Order that a focus be placed on energy efficiency for low-income consumers. The Commission ordered "When the FEECA utilities file their DSM implementation plans, each plan should address how the utilities will assist and educate their low-income customers, specifically with respect to the measures with a two-year or less payback."² Further discussion of the utilities' low-income programs can be found in Section 2.4 of this report.

Following the Commission's establishment of the goals in late 2014, the IOUs filed DSM plans to meet the Commission's goals. In mid to late 2015, the Commission approved the IOUs' DSM plans. Subsequently, in late 2015, the IOUs filed program standards with the Commission to support these plans. At the end of 2015, the Commission approved the program standards for each IOU. The IOUs implemented the new programs in late 2015 and early 2016.

Conclusion

The potential demand and energy savings from utility-sponsored DSM programs are affected by consumer education and behavior, building codes, and appliance efficiency standards. Consumer actions to implement energy efficiency measures outside of utility programs, as well as codes and efficiency standards, create a baseline for a new program's cost-effectiveness and reduce the potential incremental electric demand and energy savings available from DSM programs.

Utilities design DSM programs to encourage conservation that exceeds the level of conservation resulting from current building codes and minimum efficiency standards. The level of savings from these programs is uncertain because it depends on voluntary participation from customers. However, all customers pay for the utility conservation programs as a portion of their monthly utility bills. Therefore, customer education on, and participation in, utility DSM programs— along with individual efforts to save electricity—are key in reducing Florida's electric demand and energy usage.

Conservation and renewable energy will play an important role in Florida's energy future. The Commission is continuing efforts to encourage cost-effective conservation, reduce the use of fossil fuels, and defer the need for new generating capacity. These initiatives support a balanced mix of resources that reliably and cost-effectively meet the needs of Florida's ratepayers.

² Order No. PSC-14-0696-FOF-EU, Docket Nos. 130199-EI through 130205-EI, In re: <u>Commission review of numeric conservation goals</u>, issued December 16, 2014.

Section 1. Florida Energy Efficiency and Conservation Act

1.1 History of FEECA

The Florida Energy Efficiency and Conservation Act (FEECA) emphasizes four key areas: reducing the growth rates of weather-sensitive peak demand and electricity usage, increasing the efficiency of electricity and natural gas production and use, encouraging demand-side renewable energy systems, and conserving expensive resources, particularly petroleum fuels. The Commission is required to establish goals, and the FEECA utilities are required to develop demand-side management (DSM) programs to achieve these goals.

Originally, all electric utilities in Florida were subject to FEECA. In 1989, changes were made to the law limiting the requirement to electric utilities with more than 500 gigawatt-hours (GWh) of annual retail sales. At that time, 12 Florida utilities met this threshold requirement, and their combined sales accounted for 94 percent of Florida's retail electricity sales. An additional change to the law encouraged cogeneration projects.

In 1996, the Florida Legislature raised the minimum retail sales threshold for subject utilities to 2,000 GWh. Retail sales for FEECA utilities were measured as of July 1, 1993, and two municipal utilities met the threshold of the new law: JEA and OUC. In addition to these two utilities, all five Florida investor-owned utilities must comply with FEECA regardless of sales levels. No rural electric cooperatives are currently subject to FEECA.

The seven electric utilities subject to FEECA currently account for approximately 84 percent of all Florida energy sales. Table 1 reflects the 2015 electricity sales and the percentage of total electricity sales by each FEECA utility, as well as the total for all non-FEECA utilities.

Florida's FEECA Utilities	Energy Sales GWh	Percent of Total Energy Sales
Florida Power & Light Company	109,820	46.9%
Duke Energy Florida, LLC	38,553	16.5%
Tampa Electric Company	19,006	8.1%
JEA	11,090	4.7%
Gulf Power Company	11,085	4.7%
Orlando Utilities Commission	6,535	2.8%
Florida Public Utilities Company	638	0.3%
FEECA Utilities' Total	196,727	84.0%
Non-FEECA Utilities' Total	37,391	16.0%
Total Statewide Energy Sales	234,118	100.0%

Table 1Energy Sales by Florida's FEECA Utilities in 2015

Source: Commission's "Statistics of the Florida Electric Utility Industry" (Table 24) published in October 2016.

1.2 Conservation Tools and DSM Savings

Although utility-sponsored DSM programs are an important means of achieving energy conservation, consumer choices and mandatory efficiency standards are also keys to reducing demand and energy growth rates in Florida. Consumers respond to price signals by taking actions, such as buying energy efficient homes, installing efficiency upgrades and demand-side renewable systems, and making behavioral changes. The Commission's initiatives to educate Florida's consumers on conservation opportunities are discussed further in Section 4 of this report.

Pursuant to Section 366.82(11), F.S., all FEECA utilities are required to offer energy audits to residential customers. Home and business energy audits serve as the basis for many DSM and conservation programs which provides utilities an avenue to identify and evaluate conservation opportunities for customers. During 2015, Florida's IOUs performed more than 194,000 residential audits. Though FEECA does not require commercial energy audits, Florida's IOUs performed more than 15,000 commercial energy audits in 2015.

The FEECA utilities evaluate conservation opportunities for their customers through 108 programs for residential, commercial, and industrial customers. Table 2 shows that since FEECA's enactment, DSM programs are estimated to have reduced summer peak demand by an estimated 7,732 MW and winter peak demand by 7,263 MW.

	Savings
Summer Peak Demand	7,732 MW
Winter Peak Demand	7,263 MW
Annual Energy Reduction	10,363 GWh

Table 2Estimated Cumulative DSM Savings Since 1980

Source: Florida Reliability Coordinating Council Load and Resource Plan 2016, S-3, S-4, S-5.

Utility-sponsored DSM programs are designed to encourage conservation efforts that exceed the minimum standards in state building codes and ever-strengthening federal appliance efficiency standards. The current level of federal efficiency standards and building codes creates a baseline used in determining the cost-effectiveness of a potential DSM program. The higher the efficiency standards and codes, the less opportunity there is for utility DSM programs to be cost-effective.

State Standards

At the state level, the Florida Building Code is amended annually to incorporate interpretations and clarifications as well as to update efficiency standards. The Florida Building Commission updates the Florida Building Code with relevant new standards every three years. The Florida Building Code's next update is scheduled for 2017. The 2014 Florida Building Code, 5th edition, places an emphasis on thermal envelopes of buildings. Additionally, the energy efficiency section focuses on insulation, ventilation measures for air conditioners, on/off switches for water heaters and pool heaters, and automatic temperature controls for hot water systems. These issues directly tie to utility and consumer energy conservation efforts.

Federal Government Standards

At the federal government level, the U.S. Department of Energy's (DOE) Building Technologies Office establishes minimum energy efficiency standards for more than 60 categories of appliances and other equipment. According to DOE, "Products covered by standards represent about 90 percent of home energy use, 60 percent of commercial building use, and 30 percent of industrial energy use."³ From August 2015 to August 2016, DOE proposed 70 rulemaking actions. DOE's rulemaking actions include final rules, notices of proposed rulemaking, preliminary analyses, framework documents, notices of data availability, proposed determinations, and requests for information. Within DOE's 70 rulemaking actions, the agency completed 28 final rules on new energy efficiency standards.

DOE's 28 final rules from August 2015 through August 2016 included the following:

- 14 conservation standards:
 - Residential boilers
 - Refrigerated beverage vending machines
 - o Ceiling fan light kits
 - High-intensity discharge lamps
 - Single package vertical heat pumps and single package vertical air conditioners
 - o Grid-enabled water heaters
 - Commercial package air conditioning and heating equipment
 - o Commercial warm air furnaces
 - Commercial and industrial pumps
 - Commercial pre-rinse spray valves
 - Regional enforcement standards for central air conditioners
 - Dehumidifiers
 - External power supplies
 - Battery chargers
- 14 test procedures:⁴
 - Residential boilers
 - Ceiling fan light kits
 - o Commercial package air conditioning and heating equipment
 - o Commercial and industrial pumps
 - o Commercial pre-rinse spray valves
 - o External power supplies
 - Battery chargers
 - Residential furnaces
 - o Clothes washers
 - Miscellaneous residential refrigeration products
 - o LED lamps
 - o Residential central air conditioners
 - Portable air conditioners
 - o Fluorescent lamp ballasts

³ <u>http://energy.gov/eere/buildings/appliance-and-equipment-standards-program</u> .

⁴ DOE verifies through testing procedures that an appliance achieves its designated energy savings.

Further details can be found on the DOE Office of Energy Efficiency and Renewable Energy's (EERE) buildings reports website at <u>http://energy.gov/eere/buildings/reports-and-publications</u>.

Table 3 describes pending standards being considered by DOE. The table also notes the expected timeframes for DOE's associated rulemakings.

Product Categories	Expected Date			
Heating Products Rulemakings				
Residential Water Heaters	March 2017			
Commercial Packaged Boilers	March 2018			
Direct Heating Equipment	March 2018			
Commercial Water Heaters	May 2018			
Space Cooling Rulemakings				
Room Air Conditioners	April 2017			
Central Air Conditioners	June 2017			
Lighting Rulemakings				
Vibration Service Lamps	December 2016			
General Service Lamps	January 2017			
Fluorescent Lamp Ballasts	October 2017			
Home Appliances Rulemakings				
Dishwashers	December 2016			
Clothes Dryers	April 2017			
Residential Ovens	May 2017			
Residential Refrigerators and Freezers	September 2017			
Clothes Dryers	January 2018			
Walk-in Coolers and Freezers	April 2018			
Residential Clothes Washers	May 2018			

Table 3
Upcoming Federal Appliance Standards Review

Source: DOE's Report to Congress, Energy Conservation Standards Activities, August 2016.

Effect of Efficiency Standards on Florida IOUs' DSM Programs

Florida utility DSM programs offer rebates and incentives for appliances that exceed federally established minimum efficiency standards. Increases in federal efficiency standards, independent conservation efforts by consumers, and general conservation practices make it more challenging for utilities to achieve additional demand and energy savings through these DSM programs. Moreover, participation rates in utility programs are driven by the anticipated payback to the participating customer. While utility incentives tend to increase customers' "take rate" in conservation programs, electric rates are also a contributing factor in customers' decisions to invest in a more efficient appliance. Thus, low or declining electric prices tend to reduce customer energy efficiency investments.

Since 2009, the cost-effectiveness of DSM measures has declined due to several factors outside of the FEECA utilities' control. First, new federal efficiency standards and state building codes have become more stringent over time. These higher standards and codes decrease the number of cost-effective DSM measures that the electric utilities can offer. Second, natural gas is the primary fuel source for electricity generation in Florida. The average price of natural gas fell from \$8.86/MMBtu in 2008 to \$3.73/MMBtu in 2013, the most recent full year before the Commission established the 2015-2024 DSM goals.⁵ In turn, lower natural gas prices reduced utility avoided costs. Lower fuel prices can impact customer participation in utility-sponsored DSM programs. For example, from October 2014 to March 2016, FPL reduced electric rates four times to reflect savings in large part due to lower natural gas prices. As a result, customers could have less of an incentive to implement energy efficiency measures.

1.3 Conservation Cost Recovery

Administrative costs, equipment, and incentive payments are all costs of implementing a DSM program. IOUs are allowed by Florida Statutes to recoup prudent and reasonable expenses for DSM programs approved by the Commission through the Energy Conservation Cost Recovery (ECCR) clause. Before attempting to recover costs through the ECCR clause, a utility must prove its DSM programs are cost-effective and benefit the general body of ratepayers. Each year, the Commission conducts financial audits of these expenses and a full evidentiary hearing is held to determine the following year's conservation cost recovery factor to be applied to customer bills.

As new cost-effective energy efficiency technologies become available, Florida's IOUs encourage customer participation by offering incentives through Commission-approved DSM programs. Utilities must also obtain Commission approval for program modifications prior to seeking cost recovery. From 2008 through 2014, there was growth in utility expenditures due to adding and modifying DSM programs.

As discussed previously, in November 2014, the Commission set lower goals for 2015 to 2024 due to finding that certain energy efficiency measures were no longer cost-effective. Most of these utility program modifications were not implemented until late 2015 to early 2016. Beginning in 2016, costs recovered through the ECCR are expected to stay flat or decline for most IOUs due to DSM program modifications.

⁵ EIA Henry Hub Natural Gas Spot Price Annual Average <u>https://www.eia.gov/dnav/ng/hist/rngwhhdA.htm</u>.

Table 4 shows the annual DSM expenditures recovered by Florida's IOUs from 2005 through 2015.

DSM Expenditures Recovered by IOUs						
	FPL	DEF	TECO	Gulf	FPUC	Total
2005	\$144,192,697	\$59,143,255	\$15,583,726	\$9,363,182	\$473,610	\$228,756,470
2006	\$146,204,978	\$59,461,107	\$14,099,638	\$9,562,098	\$456,161	\$229,783,982
2007	\$160,749,639	\$67,109,875	\$13,652,585	\$9,107,192	\$515,022	\$251,134,253
2008	\$180,016,994	\$77,593,960	\$16,989,411	\$9,257,740	\$534,350	\$284,392,455
2009	\$186,051,381	\$80,954,071	\$32,243,315	\$10,576,197	\$540,433	\$310,365,397
2010	\$216,568,331	\$85,354,924	\$43,371,442	\$9,859,407	\$693,331	\$355,847,435
2011	\$228,293,640	\$91,738,039	\$43,349,092	\$15,003,596	\$954,297	\$379,338,664
2012	\$224,033,738	\$93,728,110	\$46,593,831	\$22,885,826	\$695,235	\$387,936,740
2013	\$244,443,534	\$115,035,455	\$47,502,652	\$27,431,962	\$806,698	\$435,220,301
2014	\$316,311,166	\$107,033,335	\$46,620,508	\$17,412,618	\$772,612	\$488,150,239
2015	\$208,643,788	\$108,455,141	\$46,516,362	\$17,961,885	\$718,616	\$382,295,792
Total						\$3,733,221,728

Table 4

Source: Docket Nos. 060002-EG through 160002-EG, Schedules CT-2 from the IOUs' May testimony.

Of note, FPL's DSM expenditures declined from \$316 million in 2014 to approximately \$209 million in 2015. The \$316 million included a one-time \$56.3 million capacity payment to Solid Waste Authority of Palm Beach County. Without this payment, FPL's 2014 ECCR expenditures would have been approximately \$260 million. In 2015, FPL experienced additional reductions in DSM expenditures resulting primarily from changes in residential heating, ventilation, and air conditioning energy-efficiency standards and the expiration of solar rebate pilots.

Figure 1 trends the annual DSM expenditures for the four largest IOUs from 2005 to 2015.



Source: Docket Nos. 060002-EG through 160002-EG, Schedules CT-2 from the IOUs' May testimony.
During the annual ECCR clause proceedings, the Commission determines the energy conservation cost recovery factors by customer class that each utility will assess to the energy and demand portions of customer bills. These factors are set using the IOUs' estimated conservation costs for the next year and reconciliation for any actual conservation cost under- or over-recovery.

In November 2016, the Commission set the ECCR factors for the 2017 billing cycle. Table 5 illustrates the five IOUs' conservation cost recovery factors for residential customers' monthly bills. For illustration purposes, these factors are applied to a typical monthly residential bill based on 1,000 kilowatt-hour (kWh) energy usage.

Utility*	ECCR Factor (cents per kWh)	Monthly Bill Impact (Based on 1,000 kWh)
FPL	**	**
DEF	0.317	\$3.17
TECO	0.225	\$2.25
Gulf	0.1	\$1.00
FPUC	0.16	\$1.60

Table 5Residential Energy Conservation Cost Recovery Factors in 2017

* While JEA and OUC fall under the FEECA Statute, the Commission does not regulate electric rates for municipal utilities.

** Pending outcome of Docket No. 160021-EI—will update.

Source: Order No. PSC-X-X-FOF-EG, Docket No. 160002-EG.

1.4 Natural Gas Conservation Cost Recovery

Commission Rule 25-17.015, F.A.C., permits natural gas distribution companies to seek recovery for costs related to Commission-approved conservation programs. Even though natural gas local distribution companies (LDCs) offer conservation programs to their customers, the Commission does not currently set conservation goals for LDCs. Natural gas conservation programs have historically spent the majority of conservation program costs in providing rebates to residential customers that support the replacement of less efficient appliances with new, energy efficient gas appliances.

In 2013, the natural gas LDCs, which already offered natural gas conservation programs to residential customers, received approval from the Commission to offer natural gas conservation programs to commercial customers.⁶ Since then, some LDCs have added commercial conservation program offerings. Starting in 2014, Peoples Gas System added the Commercial New Construction, Commercial Appliance Retention, and Commercial Appliance Replacement Programs. In 2016, St. Joe Natural Gas added a Large Food Service Commercial Conservation Rebate Program and a Commercial Hospitality and Lodging Program, which encourages owners of lodging facilities to purchase energy efficient natural gas appliances.

⁶ Order No. PSC-14-0039-PAA-EG, Docket 130167-EG, In re: <u>Petition for approval of natural gas energy</u> <u>conservation programs for commercial customers, by Associated Gas Distributors of Florida,</u> issued January 14, 2014.

Table 6 shows the amount each LDC recovered in natural gas conservation expenditures from 2006-2015.

Year	Peoples Gas System	Florida City Gas	Florida Public Utilities	Chesapeake Utilities	Indiantown Gas Company	St. Joe Natural Gas	Sebring Gas System	Total
2006	\$8,934,625	\$2,176,960	\$2,032,704	\$967,263	\$0	\$9,175	\$0	\$14,120,727
2007	\$7,367,135	\$2,345,976	\$2,249,573	\$906,159	\$15,563	\$73,171	\$12,344	\$12,969,921
2008	\$5,730,116	\$2,678,650	\$1,962,670	\$714,243	\$11,970	\$116,975	\$6,816	\$11,221,440
2009	\$5,880,890	\$2,254,121	\$1,702,041	\$710,850	\$21,682	\$137,675	\$11,926	\$10,719,185
2010	\$5,721,003	\$3,404,142	\$2,084,724	\$627,734	\$8,733	\$170,374	\$37,283	\$12,053,993
2011	\$6,906,668	\$3,573,513	\$3,163,050	\$755,779	\$11,357	\$106,300	\$34,640	\$14,551,307
2012	\$7,314,940	\$3,743,811	\$2,655,654	\$806,747	\$5,238	\$102,425	\$25,090	\$14,653,905
2013	\$9,432,551	\$4,342,603	\$2,935,140	\$742,412	\$10,222	\$96,575	\$53,967	\$17,613,470
2014	\$11,229,211	\$5,343,191	\$3,844,386	*	*	\$128,000	\$58,382	\$20,603,170
2015	\$12,335,245	\$5,240,383	\$6,768,175		•	\$123,400	\$33,563	\$24,500,766
Total								\$153,007,884

Table 6 Conservation Expenditures Recovered by LDCs

Source: Docket Nos. 060004-GU through 160004-GU, Schedules CT-2 from LDCs' May testimony.

* Spending combined with Florida Public Utilities Company

Figure 2 trends the annual conservation expenditures for all LDCs from 2006 to 2015.



Figure 2

Source: Docket Nos. 060004-GU through 160004-GU, Schedules CT-2 from May testimony.

In November 2016, the Commission set the natural gas conservation cost recovery factors for the 2017 billing cycle. Table 7 provides the LDCs' conservation cost recovery factors for 2017 and the impact on a typical residential customer's bill using 20 therms of natural gas per month.

Utility	Cost Recovery Factor (Cents per Therm)	Monthly Bill Impact (Based on 20 Therms)
Peoples Gas System	7.853	\$1.57
Florida City Gas	15.168	\$3.03
Florida Public Utilities	13.261	\$2.65
Chesapeake Utilities	31.789	\$6.36
Indiantown Gas Company	12.751	\$2.55
St. Joe Natural Gas	40.001	\$8.00
Sebring Gas System	19.897	\$3.98

Table 7Residential Natural Gas Conservation Cost Recovery Factors in 2017

Source: Order No. PSC-X-X-FOF-GU, Docket 160004-GU.

Section 2. Analytics for Setting DSM Goals

2.1 Cost-Effectiveness

Utility-sponsored DSM programs can benefit the general body of electric ratepayers by offsetting the need for future power plant construction. These programs can reduce costs to ratepayers by postponing capital expenditures, improving reliability, and reducing current electrical generation costs, including fuel and variable operating and maintenance costs. However, the deferral of new power plants with advanced technology can forgo the benefits of more efficient power generation and the associated lower emission rates for certain regulated pollutants.

Section 366.82, F.S., requires utility conservation programs to be cost-effective. This statute is codified in Rule 25-17.008, F.A.C., which identifies the cost-effectiveness methodologies to be used and requires that utilities provide cost and benefit information to the Commission when requesting to add or make changes or additions to an existing program. In order to be eligible for cost recovery, the utilities are required to provide a cost-effectiveness analysis for each proposed program or program modification. The Commission requires utilities to provide three cost-effectiveness tests for its consideration: the Participants Test, the Rate Impact Measure (RIM) test, and the Total Resource Cost (TRC) test. The tests are summarized below.

Participants Test

The Participants Test analyzes costs and benefits from a program participant's point of view and ignores the impact on the utility and other ratepayers not participating in the program. The Participants Test includes the costs customers pay for equipment and maintenance. Benefits considered in the test include the incentives paid by utilities to the customers and the reduction in customer bills. Failure to demonstrate cost-effectiveness under this test would infer that rational customers would not elect to participate in this program.

Rate Impact Measure Test

The RIM test is designed to ensure that all ratepayers, not just the program's participants, will benefit from a proposed DSM program. The RIM test includes the costs associated with incentive payments to participating customers and decreased revenues to the utility. DSM programs can reduce utility revenues due to reduced kWh sales and reduced demand. The decreased utility revenues typically are recovered from the general body of ratepayers at the time of a rate case. A DSM program that passes the RIM test ensures that all customer rates are lower than rates would be without the DSM program.

Total Resource Cost Test

The TRC test measures the overall economic efficiency of a DSM program from a social perspective. This test measures the net costs of a DSM program based on its total costs, including both the participants' and the utility's costs. Unlike the RIM test, customer incentives and decreased utility revenues are not included as costs in the TRC test. Instead, these factors are treated as transfer payments among ratepayers.

Moreover, if appropriate, certain external costs and benefits such as environmental impacts may be taken into account. Because incentives and foregone revenues are not treated as "costs", electric rates for all customers tend to be higher for programs implemented using the TRC test to judge cost-effectiveness. Table 8 illustrates the costs and benefits considered in the three Commission-approved costeffectiveness methodologies.

	Participants	RIM	TRC
Benefits			
Bill Reduction	X		
Incentives Received	X		
Avoided Generation (Capital and O&M)		X	X
Avoided Transmission (Capital and O&M)		X	X
Fuel savings		Χ	Χ
Costs			
Program Costs		X	X
Incentives Paid		X	
Lost Revenues		X	
Participant's Costs (Capital and O&M)	X		X

 Table 8

 Summary of Cost-Effectiveness Methodologies

When IOUs determine that their programs are no longer cost-effective, the utilities must petition the Commission for modification or discontinuation of the program. For example, programs may need to be modified due to the adoption of a more stringent appliance efficiency standard or building code. In contrast, if new efficiency measures become available that are cost-effective, the utility may petition the Commission for approval of a new program.

In 2008, the Florida Legislature amended the FEECA statute, placing upon the Commission additional responsibilities when adopting conservation goals. These responsibilities include the consideration of benefits and costs to program participants and ratepayers as a whole, as well as the need for energy efficiency incentives for customers and utilities. The Commission must also consider any costs imposed by state and federal regulations on greenhouse gas emissions.

The amended FEECA statute allows the Commission to provide appropriate financial rewards and penalties to the utilities over which it has rate-setting authority. Additionally, the 2008 legislation authorized the Commission to allow an IOU to receive an additional return on equity of up to 50 basis points for exceeding 20 percent of its annual load growth through energy efficiency and conservation measures. To date, the Commission has not awarded financial rewards or assessed penalties for IOUs through FEECA.

2.2 Commission-Established Goals

After considering the evidence in the 2014 goal-setting proceeding, the Commission established goals for the FEECA utilities based on the RIM cost-effectiveness analysis.⁷ The RIM test

⁷ Order No. PSC-14-0696-FOF-EU, Docket Nos. 130199-EI through 130205-EI, In re: <u>Commission review of numeric conservation goals</u>, issued December 16, 2014.

ensures that all ratepayers, both participants and non-participants, benefit from utility-sponsored conservation programs. Additionally, the RIM test minimizes cross subsidies between customers. By setting goals based on the RIM test in 2014, the Commission addressed concerns voiced at the hearing regarding subsidies between individuals who participate in DSM programs and individuals who do not participate.

In accordance with Section 366.82(7), F.S. (Florida Statues), in March 2015 the utilities filed DSM plans to meet the new goals. The Commission approved the utilities' DSM plans in August 2015. In fall 2015, the utilities submitted their program standards for approval. The 2014 goal setting process is further discussed in Section 2.4.

Table 9 shows the Commission-approved summer demand, winter demand, and annual energy reduction goals for 2015-2024 established in Order No. PSC-14-0696-FOF-EU.

Electric Utility	Summer Demand Goals (MW)	Winter Demand Goals (MW)	Annual Energy Goals (GWh)
FPL	526.1	324.2	526.3
DEF	259.1	419.3	195.0
TECO	56.3	78.3	144.3
Gulf	68.1	36.7	84.2
FPUC	1.3	0.4	2.0
OUC	5.0	8.4	13.0
JEA	10.8	9.7	25.8
Total	926.7	877.0	990.6

Table 9Commission-Approved DSM Goals 2015-2024

Source: Order No. PSC-14-0696-FOF-EU.

2.3 Assessing Goal Achievement

Commission rules require separate goals be set for residential and commercial/industrial (C/I) customers, assigning context to measuring goal achievement within these two primary customer categories. Each utility's achievements in these categories are also combined and compared against total goals; the value of a system's demand and energy savings has no relation to the sector—C/I or residential—in which the savings occur.

Each FEECA utility must file an annual report for the Commission summarizing demand savings, energy savings, and customer participation rates for each approved program. The FEECA utilities also present, pursuant to Rule 25-17.0021, F.A.C., the residential, C/I, and total energy efficiency achievements compared to the approved DSM goals. The annual reports are on the Commission website at the following link:

http://www.floridapsc.com/ElectricNaturalGas/ARDemandSidePlans.

Monitoring annual goal achievements enables the Commission to evaluate the effectiveness of each utility's programs. In addition to reviewing the annual reports, staff may request additional information from the FEECA utilities on their demand and energy saving achievements. Staff's

data requests can, for example, seek explanations of factors preventing the utilities from achieving projected participation levels.

Table 10 shows the 2015 residential, C/I, and total goals and achievements for each utility. Numbers in **bold** highlight that a utility did not achieve its goals in a particular category.

Utility	Win	ter (MW)	Sum	Summer (MW)		Annual (GWh)	
	Goals	Achieved Reduction	Goals	Achieved Reduction	Goals	Achieved Reduction	
FPL							
Residential	16	33	25	59	22	108	
Commercial/Industrial	14	12	23	27	20	49	
Total	29	45	48	86	41	156	
DEF							
Residential	58	41	26	25	26	39	
Commercial/Industrial	5	28	12	35	15	36	
Total	64	69	38	60	40	76	
TECO							
Residential	3	12	1	11	2	21	
Commercial/Industrial	1	8	2	12	4	13	
Total	4	20	3	23	6	34	
Gulf							
Residential	1.3	12.7	2.3	13.0	2.3	34.2	
Commercial/Industrial	0.1	4.2	0.3	6.4	0.8	13.8	
Total	1.4	17.0	2.6	19.6	3.1	48.3	
FPUC							
Residential	0.1	0.4	0.2	0.8	0.4	1.5	
Commercial/Industrial	0.1	0.0	0.1	0.0	0.1	0.0	
Total	0.2	0.4	0.3	0.8	0.5	1.5	
JEA							
Residential	1.0	2.5	0.9	3.3	2.5	7.2	
Commercial/Industrial	0.0	0.0	0.1	0.1	0.1	0.2	
Total	1.0	2.5	1.1	3.3	2.6	7.4	
OUC							
Residential	0.0	0.4	0.1	0.4	0.1	0.8	
Commercial/Industrial	0.5	0.7	0.2	2.2	0.3	13.4	
Total	0.5	1.1	0.3	2.6	0.5	14.2	

Table 10		
DSM Goals Compared to Annual ((2015)	Achievements

*Bold numbers indicate the utility did not meet its annual goals within that category. Source: FEECA utility demand-side management annual reports.

Each utility's DSM performance in 2015 is discussed below. The 2015 utility achievements have been compared to the 2015 goals established by the Commission in November 2014. Of note, the approved modifications to most of the utilities' DSM plans did not go into effect until late 2015.

FPL

Overall, FPL met its 2015 total goals. However, FPL achieved only 85 percent of its C/I winter MW goal. The company stated that the implementation date of its Energy Recovery Ventilation and Demand Control Ventilation measures affected its results.

DEF

Overall, DEF met its 2015 total goals. However, for residential customers, DEF achieved only 96 percent of its summer peak demand savings goal and only 71 percent of its winter MW peak demand savings goal.

The company commented that the Residential Energy Management Program achieved fewer participants than projected. Additionally, DEF expressed that measures to achieve the residential goal were delayed pending approval of its DSM Program Standards. Lastly, DEF stated that its savings from commercial programs made up for the residential shortfall.

TECO

TECO met its 2015 total goals and all individual goals.

Gulf

Gulf met its 2015 total goals and all individual goals.

FPUC

FPUC met its 2015 total goals. However, for the C/I goals, FPUC achieved 0 percent of its winter MW goal, 0 percent of its summer MW goal, and 8 percent of its annual GWh goal. FPUC stated that it has made modifications to its DSM programs focused on C/I customers and that the timing of the Commission's approval of the DSM program plan hindered meeting the C/I goals in 2015.

JEA

Overall, JEA met its 2015 total goals. For the C/I goals, JEA achieved only 36 percent of its summer MW goal. JEA states that it fell short because of lower than expected participation in the commercial solar net metering program. Additionally, JEA comments that it exceeded the summer peak demand savings goal when one considers non-RIM DSM programs.

OUC

OUC met its 2015 total goals and all individual goals.

2.4 Summary of the 2014 DSM and Goal Setting Process

In mid 2013, the Commission set a schedule to establish goals for the seven FEECA utilities by December 2014. This ensured that the Commission met the statutory requirement specifying goals must be reviewed at least every five years. Both FPUC and OUC independently filed petitions to use proxy methodologies to establish their goals. These utilities stated that costs associated with updating the 2009 Technical Potential Study, performing the subsequent analyses required by the Order Establishing Procedure, and testifying in support of the analyses would represent a hardship to the companies and their ratepayers due to each company's small size. On August 4, 2013, the Commission voted to approve the proxy methodologies and excuse FPUC and OUC from participating in the goals hearing.⁸

⁸ Order No. PSC-13-0645-PAA-EU, Docket Nos. 130204-EM and 130205-EI, issued December 4, 2013.

On July 21 and July 22, 2014, the Commission heard evidence from FPL, DEF, TECO, Gulf, JEA, and intervenors regarding the proposed DSM goals. Highlights from the proceeding included discussions regarding the FEECA utilities' numerical goals, payback/subsidization, consumer education, and solar initiatives. When setting the goals, the Commission considered the costs and benefits of conservation programs to customers who choose to participate in a program, as well as costs and benefits to customers who do not participate. The Commission considered both participants and non-participants as costs are recovered from the general body of ratepayers.

Based on evidence from the DSM goals setting proceeding, on November 25, 2014, the Commission voted to approve goals based on a RIM cost-effectiveness analysis. By approving goals based on the RIM test, the Commission ensured that rates would remain the same or lower than rates would otherwise have been and that cross subsidies among ratepayer groups would be minimized. In addition, the Commission directed each utility to demonstrate in its DSM plan how it would make all customers, in particular low-income customers, aware of energy efficiency opportunities and utility programs.

The Commission also voted to allow the IOUs' five-year solar pilot programs to end on December 31, 2015. The Commission based its decision on evidence in the record that the existing solar pilot programs were not cost-effective and represented a subsidy between the general body of ratepayers and the limited participants in the programs. The Commission issued the DSM Final Order, Order No. PSC-14-0696-FOF-EU, on December 16, 2014. The utilities subsequently filed DSM plans designed to meet the newly established goals. The Commission approved the utilities' DSM plans in August 2015. Beginning in late 2015, the FEECA utilities began implementing program modifications to reflect the Commission's orders.

In fall 2015, the FEECA utilities submitted, for approval, their program standards providing detailed descriptions on the administrative approaches for each DSM program. Beginning in late 2015, the FEECA utilities began implementing program modifications to reflect the approved DSM plans.

Low-Income Programs

In the November 2014 DSM goal-setting proceeding, the Commission ordered the FEECA utilities to educate low-income customers on energy efficiency opportunities. The Commission Order states "When the FEECA utilities file their DSM implementation plans, each plan should address how the utilities will assist and educate their low-income customers, specifically with respect to the measures with a two-year or less payback."⁹

Each FEECA utility implemented programs within its DSM plan that address low-income conservation efforts. For each company, these programs mainly focus on efforts to provide weatherization opportunities and installation of energy efficient appliances to residential homes. In many cases, the utilities have established partnerships with government and non-profit agencies to develop programs that educate low-income customers on conservation and the financial benefits of using less energy.

⁹Order No. PSC-14-0696-FOF-EU, Docket Nos. 130199-EI through 130205-EI, In re: <u>Commission review of numeric conservation goals</u>, issued December 16, 2014.

Utilities also educate all customers on conservation opportunities through energy audits, bill inserts, presentations, and other measures. This report discusses the utilities' conservation efforts with respect to low-income customers below.

FPL

FPL states its energy efficiency activities initially target low-income customers through energy efficiency education. FPL's Residential Energy Survey identifies energy-saving opportunities through changes that come at little to no costs. Next, FPL's Residential Load Management program provides bill credits to residential customers of all income levels who are willing to have electric service briefly interrupted during grid emergencies. Finally, FPL's Low-Income Program is aimed exclusively at low-income customers. This program "assists low-income customers through (first) state Weatherization Assistance Provider ("WAP") agencies and (second) FPL conducted Energy Retrofits."¹⁰

DEF

DEF states that for its low-income customers, the company first offers information about energy conservation programs through bill inserts and through DEF's website. Next, the company offers the Neighborhood Energy Saver Program, which includes booklets to customers about potential energy efficiency improvements. The booklets also include phone numbers for conservation programs and the company's website links to information about energy efficiency rebates and incentives offered through Residential Incentive Programs, EnergyWise, and the Low-Income Weatherization Assistance Program. Specifically, the Low-Income Weatherization Assistance Program uses installations and incentives to weatherize (protect a home from the outside elements) the homes of low-income families.

DEF also provided a home energy report in 2016 to approximately 15,000 low-income customers. The home energy report shows where homes are using electricity inefficiently. The home energy report includes information about DEF's Low-Income Weatherization Assistance Program and low-cost and no-cost ways that customers can reduce electric consumption. Furthermore, DEF's Weatherization Program partners distribute information about energy conservation programs. Finally, DEF makes periodic presentations on energy education and participates in energy fairs and low-income meetings throughout Florida.

TECO

TECO states that in low-income neighborhoods recognized by the U.S. census bureau, the company conducts Neighborhood Weatherization work when customers reach out to the weatherization independent contractor listed on the company's website. The Neighborhood Weatherization Program provides and/or installs the necessary materials for energy conservation for low-income customers.

Also, TECO Energy Management Services team members participate in local community events and fairs to educate customers on DSM opportunities and how to participate in these programs. Furthermore, in low-income neighborhoods, TECO performs door-to-door advertising on energy efficiency opportunities. Finally, TECO works with Neighborhood Service Centers, Senior Outreach Centers, and Elder Affairs Centers to present advice on energy efficiency.

¹⁰ Docket No. 160002-EG, FPL's August 2016 filing, Document No. 06880-16.

Gulf

Gulf works with local assistance agencies to present energy conservation information through an "energy literacy" curriculum to low-income customers. Also, Gulf's Community Energy Saver Program installs energy conservation measures at no cost to low-income families.

In addition to presenting in person through local assistance agencies, Gulf provides energy efficiency advice through company representatives as appropriate when customers call or visit. Moreover, Gulf offers home energy audits in which company representatives present advice on lowering electricity consumption. Finally, Gulf presents energy conservation advice to its customers through its website.

FPUC

FPUC states its Low-Income Energy Outreach Program partners with the Florida Department of Economic Opportunity and the department's approved Low-Income Weatherization Program operators to offer residential energy surveys, weatherization contractor training, and energy efficiency educational literature to low-income households.

JEA

JEA states its Neighborhood Efficiency Program "offers education concerning the efficient use of energy and water as well as the direct installation of an array of energy and water efficient measures at no cost to income qualified customers."¹¹

OUC

OUC states its Residential Efficiency Delivered Program, an income based program, "provides up to \$2,000 of energy and water efficiency upgrades, based on the needs of a customer's home."¹² A conservation specialist from OUC performs a home survey and advises customers on the home improvements that can save the customer the most on utility bills.

Solar Pilot Programs

In 2009, the Commission ordered the IOUs to spend 10 percent of each company's historic energy conservation cost recovery expenditures as an annual cap for solar water heating and solar photovoltaic (PV) pilot programs.¹³ As part of its proposed DSM plan, each IOU proposed solar pilot programs. The Commission approved these programs in 2010 and 2011.

To comport with the 2009 FEECA revision encouraging demand-side renewables, the Commission approved solar pilot programs, even though these programs were determined not to be cost-effective. The Commission's intent was to evaluate the results of the pilot programs in a subsequent goals proceeding. Table 11 represents the Commission-approved annual expenditure caps for the IOUs' solar pilot programs through 2015.

¹² OUC's 2015 Annual Demand-Side Management Report

¹¹ JEA's 2015 Annual Demand-Side Management Report

http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/ARDemandSide/2015/JEA.pdf.

http://www.psc.state.fl.us/Files/PDF/Utilities/Electricgas/ARDemandSide/2015/Orlando%20Utilities%20Commissi on.pdf. ¹³Order No. PSC-09-855-FOF-EG, Docket Nos. 080407-EG through 080413-EG, In re: <u>Conservation review of</u>

numeric conservation goals, issued December 30, 2009.

Table 11Commission-Approved Annual Expenditures forSolar Pilot Programs

Utility	Annual Expenditure Cap
FPL	\$15,536,870
DEF	\$6,467,592
TECO	\$1,531,018
GULF	\$900,338
FPUC	\$47,233
Total	\$24,483,051

Source: Order No. PSC-09-0855-FOF-GU.

During 2015, the IOUs provided 2,135 solar photovoltaic and water heating rebates for the residential and commercial sectors. For many of the IOUs, these programs reached capacity just hours after approval, demonstrating a high customer demand for solar photovoltaic rebates.

The IOUs also funded solar thermal (water heating) pilots for low-income customers as well as other residential and commercial customers. In addition, FPL, DEF, and Gulf offered solar pilot programs to fund photovoltaic panels for select schools through 2015.

Table 12 reflects the number of photovoltaic and solar water heating installations by the five IOUs in the residential and commercial sectors for 2015.

Solar Pilot Progra	m insta	llation	s in 201:)		
Installations	FPL	DEF	TECO	Gulf	FPUC	Total
Residential Solar Water Heating	931	320	54	21	-	1,326
Commercial Solar Water Heating	1	-	-	-	-	1
Residential Photovoltaic	431	154	53	47	8	693
Commercial Photovoltaic	79	29	2	5	-	115
Total	1,442	503	109	73	8	2,135

Table 12Solar Pilot Program Installations in 2015

Source: 2015 Annual DSM Reports by the Florida IOUs.

Table 13 reflects the IOUs' 2015 photovoltaic and solar water heating installation expenditures.

Solar Water Heating and Photovoltaic Expenditures in 2015					5	
Expenditures	FPL	DEF	TECO	Gulf	FPUC	Total
Solar Water Heating	\$2,701,226	\$302,460	\$64,962	\$8,001	\$0	\$3,076,649
Photovoltaic	\$12,180,078	\$5,220,522	\$1,211,020	\$483,354	\$40,013	\$19,134,987
Total	\$14,881,304	\$5,522,982	\$1,275,982	\$491,355	\$40,013	\$22,211,636

Table 13Solar Water Heating and Photovoltaic Expenditures in 2015

Source: 2015 Annual DSM Reports by the Florida IOUs.

In the 2014 DSM goals docket¹⁴ the Commission voted to let the solar pilot programs expire at the end of 2015. Analysis of the pilot programs' results showed that the programs were not costeffective, indicating that there were cross subsidies between participants and non-participants. In addition, the costs of solar photovoltaic systems had decreased significantly since the pilot programs were initiated, making utility rebates less necessary.

Community Solar Programs

Several FECCA utilities have implemented programs allowing their customers to voluntarily participate in the development and purchase of renewable solar generation. The Commission reviews these programs for the IOUs.

FPL

FPL offers SolarNow, a voluntary community solar program in which customers pay an additional \$9 per month to support the development of solar projects. In return, customers promote solar in Florida and receive invitations to local events, discounts, and gift certificates to local restaurants.

TECO

TECO's Renewable Energy Program allows customers to purchase blocks of renewable energy from a combination of TECO-owned solar arrays dedicated specifically to the Renewable Energy Program and of purchased biomass generated electricity. Customers pay an extra \$5 for each 200 kWh block of renewable energy purchased.

Gulf

Gulf's Solar Energy Share offers 750 kWh of solar to its customers for an annual participation fee of \$89 or \$99. Participating customers receive bill credits of up to \$2.50 per subscription per month. Gulf obtains the solar power from a 1 MW solar facility that it operates.¹⁵

JEA

JEA offers JEA SolarSmart, a program in which customers who do not have solar panels can request that solar energy generate a percentage or all of the electricity that they consume. A customer who elects for solar energy to generate an amount equal to 50 percent of their electricity consumption would pay a premium of approximately \$20 per month.¹⁶

OUC

OUC's Community Solar Program allows customers to subscribe to blocks of solar power generating 1 kW up to a maximum of 15 kW. The one-time deposit fee is \$50, and the rate for solar power is \$0.13/kWh, a premium over OUC's \$0.098/kWh charge for the first 1,000 kWh and \$0.118/kWh charge for all additional kWh.

Florida's utilities also conducted research related to renewables in their DSM programs. FPL finalized its Renewable Research & Demonstration Project. Several other IOUs noted that their own renewable research and development programs would be finalized at the end of 2015.

¹⁴Order No. PSC-14-0696-FOF-EU.

¹⁵Order No PSC-16-0119-TRF-EG, Docket No. 150248-EG, In re: Petition for approval of community solar pilot program, by Gulf Power Company, issued March 21, 2016. ¹⁶ <u>https://www.jea.com/solarsmart/</u>

Florida Utilities' Research & Development Programs

Florida's IOUs have research and development programs to learn about the technical and economic potential of various energy conservation and renewable energy technologies. In these programs, Florida's IOUs often partner with universities or established industry research organizations, such as the Electric Power Research Institute (EPRI).

FPL

In its continuing Conservation Research and Development (CRD) Program, FPL recently investigated smart thermostats, where FPL found electricity savings of 2.8 percent of total electricity consumption and 11.9 percent of air conditioning consumption were possible. FPL also researched learning thermostats and discovered that learning thermostats could help owners of single family homes save 1.3 kWh a day, or 2.4 percent, of consumption.

Next, in the CRD program, FPL found that rooftop heating, ventilation, and air conditioning (HVAC) units retrofitted with variable speed drives could reduce kWh consumption by 49 percent for air conditioners, 37 percent for compressors, and 56 percent for supply fans. Lastly, FPL investigated advanced metering infrastructure (AMI)-enabled load control switches and found that they are capable of communicating and being controlled by the AMI network. However, FPL believes that AMI-enabled load control switches are not ready to replace switches currently used in FPL's Residential Load Management Program because some features needed refinement in order to meet FPL's operational criteria.

In its concluded Renewable Research and Development (RRD) Pilot Program, FPL investigated solar heat pumps and determined that a solar heat pump system can technically achieve over 70 percent of annual space conditioning energy usage. Though the technology works, FPL believes that the payback of 20 years is unattractive for consumers. Additionally, in its RRD program, FPL examined a solar assisted air-conditioning unit and found that adding a solar collector between an air-conditioner's compressor and condenser is ineffective.

FPL states it found solar trackers to be effective, generating approximately 16 percent more annual energy than a fixed solar array. FPL also found cooled hybrid photovoltaic thermal solar cells generate 20 percent more electricity on average than un-cooled thermal solar cells. Lastly, FPL studied solar hybrid thin-film panels and compared them to Trina Solar's crystalline panels. FPL found the difference in output was less than 2 percent.

DEF

DEF's continuing Technology Development Program supported the EPRI SolarTAC (Solar Technology Acceleration Center) Project. The project found that PV capacity factors ranged from 0.16 to 0.26 and that PV module nameplate ratings need standardization.

DEF also worked with EPRI to analyze the Duke Energy Distributed Photovoltaic (DPV) Monitoring Project in Florida and North Carolina. EPRI found that the difference in geography from one part of Florida to another could influence solar panel performance by 17 percent.¹⁷

In its final project, DEF engaged in the University of South Florida Sustainable Electric Energy Delivery System (SEEDS) Project. Duke installed PV and energy storage together on and near

¹⁷ Duke Energy Distributed Photovoltaic Monitoring in Florida and North Carolina, page viii. <u>http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002003996</u>.

the St. Petersburg campus of the University of South Florida. In the SEEDS Project, Duke used energy storage to smooth out the occasional intermittency of PV as well as to time-shift the output of PV to power system peak times.

TECO

In its continuing DSM Research and Development Program, TECO is studying thermal energy storage, such as including residential heat pump water heaters and hybrid water heaters in its Residential Price Responsive Load Management (Energy Planner) Program as an electric thermal storage device. Additionally, TECO is exploring battery storage in C/I facilities for the purpose of shifting electrical consumption from peak to non-peak times. Also, the company's continuing Renewable Energy Program allows its customers to purchase 200 kWh blocks of renewable energy and allows TECO to evaluate the technical and economic potential of renewable energy technologies.

TECO's Renewable Energy Systems Initiative Pilot Program found the cost of solar in \$/kilowatt of direct current fell 43 percent from 2011 to 2015. Furthermore, TECO's Renewable Energy Systems Initiative Pilot Program determined that homeowners who installed solar systems can have problems with shading from trees, adjacent homes, or buildings. TECO also determined that many homes that could support fixed solar panels cannot support a more optimal tilt angle for the panels or a better axis orientation to increase solar energy collected.

Gulf

Gulf's continuing Conservation, Demonstration, and Development Program is studying three projects in 2016. First, the Azalea Trace Project is obtaining data on the application of a heat pump water heater. The company's 10th Avenue North Hair Salon Heat Pump Water Heater project is evaluating a heat pump water heater. This project is studying whether a residential heat pump water heater can be used successfully in small commercial applications with high usage. Third, Gulf is launching the Residential Service Time of Use Pilot Program to measure customers' response to a variable electricity price.

Section 3. Overview of Florida's Electricity Market

3.1 Energy Demand in Florida

Florida's total electric consumption ranks among the highest in the country largely due to its sizeable population and climate-induced high demand for cooling. The state's large residential customer base influences the unique pattern of electrical demand and energy consumption. Florida's load patterns are driven by high air-conditioning loads in the summer and greater reliance on electricity rather than natural gas for heating in the winter, resulting in large swings in peak demand throughout the year. Understanding these patterns, and why they occur, is imperative to recognizing the importance of conservation in Florida.

Table 14 shows residential customers comprise approximately 89 percent of Florida's total electricity customers, while purchasing approximately 53 percent of its electrical energy. Florida's commercial class comprises approximately 11 percent of the total customers and purchases approximately 39 percent of its electrical energy. Industrial customers purchase the remaining 8 percent of electricity in Florida.

Florida's Electric Customers by Class and Consumption in 2015						
Customer	Number of	Percent of Energy Sale		Percent of		
Class	Customers	Customers	(GWh)	Sales		
Residential	8,659,510	88.7%	117,615	53.2%		
Commercial	1,082,577	11.1%	86,027	38.9%		
Industrial	22,703	0.2%	17,342	7.8%		
Total	9,764,790	100.0%	220,984	100.0%		

Table 14
Florida's Electric Customers by Class and Consumption in 2015

Source: 2016 Florida Reliability Coordinating Council Load and Resource Plan S-2.

Florida versus National Averages for Residential Electric Consumption

Florida's electric consumption is more dominated by residential consumers than the national average. In Florida, as shown in the above table, residential customers account for 53.2 percent of total electric sales. In contrast, nationally residential customers account for only 36 percent of total electric sales, while commercial customers represent 35 percent of electric consumption and industrial customers represent 26 percent.¹⁸ The remaining 3 percent of national electric consumption is direct use.

Because Florida has a higher than average proportion of residential electric consumption, Florida's load follows residential load patterns. Compared to commercial or industrial loads, residential load is more rapidly shifting and has higher peak to trough variation. In response, many Commission-approved DSM programs are designed to lower or shift peak demand in order to reduce the need for expensive new power plants.

Small and medium commercial loads are highest during the traditional workday. Large commercial and industrial loads demonstrate more consistency throughout the 24 hour day and

¹⁸ <u>http://www.eia.gov/electricity/data.cfm#sales</u> Retail sales of electricity to ultimate consumers, annual, by sector by provider.

experience fewer spikes in demand. Therefore, states that have a larger industrial presence than Florida have flatter, more consistent demand for electricity than Florida.

Effect of Weather on Electric Consumption in Florida

For residential customers throughout the U.S. and in Florida, residential electricity consumption peaks in early evening in the summer. With higher temperatures and humidity than other states, Florida's residential load can have higher peaks compared to other states.

Similarly, for residential customers throughout the U.S. and in Florida, residential energy usage peaks mid-morning and late evening in the winter. Furthermore, due to the warm climate, Florida has less of a need for heating in the winter, although Florida relies more on electricity for heating compared to other states that use more direct natural gas for heating, or even heating oil.

Due to the warm weather, Florida is typically a summer-peaking state, with peak demand often coming on the hottest weekdays of the year when the need for air-conditioning is greatest. Because Florida is summer peaking, summer peak demand generally controls the amount of required generation. Florida's 2015 summer peak demand was 48,800 MW, while the winter peak demand was 40,754 MW.¹⁹

Figure 3 shows the daily load curves for a typical Florida summer and winter day. In the summer, air-conditioning demand starts to increase in the morning and peaks in the early evening; a pattern which aligns with the sun's heating of buildings. In comparison, the winter load curve has two peaks-the largest in mid-morning, followed by a smaller peak in the late evening—which correspond to heating loads.



Figure 3

Source: Ten-Year Site Plan responses provided to the Commission by the IOUs in the 2015 first Data Request.

¹⁹ 2016 FRCC Load and Resource Plan, S-1.

https://www.frcc.com/Planning/Shared%20Documents/Load%20Resource%20Plans/FRCC%202016%20Lo ad%20and%20Resource%20Plan.pdf.



3.2 Florida's Electric Generating Resources

Florida's electric utilities' resource-planning process aims to guarantee enough installed capacity is available to meet projected customer demand and to provide a contingency reserve in the event of planned outages, forced outages, or spikes in load. Once the timing of capacity additions is known, the appropriate generating technology and fuel type is determined to provide the needed energy and maintain reliability. Electric generating units typically are categorized as baseload, intermediate, or peaking.

Aside from planned and forced outages, baseload units are scheduled to operate continuously. Intermediate units generate power to follow load for periods of time, but are not planned to operate nonstop. Peaking units supplement baseload and intermediate power, operating less frequently during high-demand periods. Utility-sponsored conservation programs help to reduce peak demand and energy consumption, offsetting the need for expensive new generating capacity.

Florida's mix of electric utilities is made up of five IOUs, 35 municipally-owned electric utilities and 18 rural electric cooperatives. In total, these utilities currently have 58,421 MW of summer electric generating capacity and 62,991 MW of winter generating capacity.²⁰ Non-utility generators in the state provide an additional 4,226 MW of summer electric generating capacity and 4,525 MW of winter generating capacity.²¹ Supplementary capacity is purchased from out-of-state utilities over the Florida-Georgia transmission interconnections.

The FEECA generating utilities currently have 46,584 MW of summer electric generating capacity and 50,227 MW of winter generating capacity. A referenced in Table 2, since inception, the FEECA DSM programs have cumulatively saved 7,732 MW of summer peak demand and 7,263 MW of winter peak demand.

²⁰ 2016 FRCC Load and Resource Plan, S-7.

https://www.frcc.com/Planning/Shared%20Documents/Load%20and%20Resource%20Plans/FRCC%202016%20Load%20and%20Resource%20Plan.pdf.

²¹ 2016 FRCC Load and Resource Plan, S-7.

https://www.frcc.com/Planning/Shared%20Documents/Load%20and%20Resource%20Plans/FRCC%202016%20Load%20and%20Resource%20Plan.pdf.

Figure 4 shows the current summer and winter capacity of each generating FEECA utility.



Figure 4 Summer and Winter Generating Capacity by FEECA Utility

Source: Florida Reliability Coordinating Council 2016 Load and Resource Plan, page 7 and page S-7.

The most prominent fuel source for generation in Florida is natural gas. Table 15 below provides a breakdown of the approximate percentage of fuel sources used to generate net energy for load in Florida.

Generation Source	Percent of Net Energy for Load
Gas	62.94%
Coal	18.79%
Nuclear	11.22%
Interchange (Exports and Imports of Power to Other States)	3.40%
Other	1.30%
Non-Utility Generation, Primarily Gas	0.74%
Municipal Solid Waste	0.59%
Biomass	0.47%
Landfill Gas	0.14%
Residual Oil	0.14%
Distillate Oil	0.10%
Solar	0.08%
Hydro	0.07%

Table 15Electric Generation Sources in Florida in 2015

Source: 2015 Actual Data from the 2016 Florida Reliability Coordinating Council Load and Resource Plan, S-18.

The low price of natural gas and recent and potential environmental regulations are expected to continue leading Florida to substitute gas generation or renewables for coal. Between 2014 and 2015, coal decreased as a percentage of generation in Florida by 4.4 percent, from 23.2 percent to 18.8 percent.²² Examples of coal plants considered for decommissioning include the 250 MW Cedar Bay plant and the 330 MW Indiantown plant. For both plants, FPL had contracts for coal-generated electricity from these facilities at prices that are now above market. The Commission approved FPL's requests to buy each plant. FPL stated that its intent is to replace the above-market coal contracts with more cost-effective energy and to potentially retire the coal plants.²³

With the trend towards natural gas, Florida's reliance on natural gas may increase beyond the current level of 62.9 percent. However, several IOUs have plans for additional renewable capacity or purchases.

FPL Solar

FPL currently has 110 MW of solar in operation.²⁴ Also, FPL is planning to add 225 MW more of solar photovoltaic (PV) by the end of 2016, with 3 large-scale 74.9 MW projects in DeSoto, Manatee, and Charlotte Counties. In FPL's most recent rate case, pending approval of a settlement agreement, FPL would build up to 300 MW of solar PV a year for the next four years. As a result, FPL would expect to have close to 1,200 MW of new solar PV, in addition to its existing 110 MW of solar and 225 MW of solar PV completed in 2016.

DEF Solar

DEF has 4 MW of solar in Osceola County, 5 MW of solar in Perry, 5 MW of solar at Disney World, and a partnership with OUC for 5.9 MW of solar at Stanton Solar Farm in Orlando for a total of 19.9 MW of utility-owned solar. By 2018, DEF expects to bring online an additional 30 MW of solar. By 2024, DEF plans to install up to 500 MW of solar generation.

TECO Solar

TECO currently has 2 MW of solar at the Tampa International Airport. By the end of 2016, TECO expects to add 23 MW of solar next to its existing coal-fired Big Bend Power Station.

Gulf Solar and Wind

Gulf is partnering with the Navy and Air Force to add 120 MW of solar by the end of 2016, with 30 MW at Eglin Air Force Base in Fort Walton Beach, 40 MW at Holley Field in Navarre, and 50 MW at Saufley Field in Pensacola. In addition to solar, Gulf has entered into purchase power agreements linked to 272 MW of wind energy produced by facilities located in Oklahoma. While the energy from the facilities may not be delivered to Gulf's system, the renewable attributes for their output are retained by the utility for the benefit of Gulf's customers.

²² 2015 actual data from the 2016 Florida Reliability Coordinating Council Load and Resource Plan S-18, and the Commission's March 2016 <u>Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act</u>.

Act. ²³ Order No. PSC-15-0401-AS-EI, Docket No. 150075-EI, In re: <u>Petition for approval of arrangement to mitigate</u> <u>impact of unfavorable Cedar Bay power purchase obligation, by Florida Power & Light Company; and Order. No.</u> <u>PSC-16-0506-FOF-EI, Docket No. 160154-EI, In re: Petition for approval of a purchase and sale agreement</u> <u>between Florida Power & Light Company and Calypso Energy Holdings, LLC, for the ownership of the Indiantown</u> <u>Cogeneration LP and related power purchase agreement</u>.

²⁴ 75MW of solar thernal and 35 MW of solar photovoltaic.



Consumer-Owned Generation

For the year ending December 31, 2015, there were 11,626 customer-owned renewable energy systems in Florida,²⁵ an increase of 35 percent from 2014.²⁶ Specifically for the five IOUs, there were 8,578 customer-owned renewable energy systems in operation, representing approximately 0.11 percent of the total customers served by these utilities.²⁷ Additionally, 249 customers of JEA and 94 customers of OUC owned renewable energy systems.²⁸

Total Renewables

According to the Commission's Ten-Year Site Plan Review, approximately 1,860 MW of Florida's generating capacity consists of renewables. Biomass and municipal solid waste represent the majority of renewables. Waste heat is third, and solar is fourth. There are 263 MW of solar in service and 1,849 MW of solar projected over the next ten years.

Other types of renewable generation in Florida include hydroelectric, landfill gas, and wind. Both Gulf and JEA have contracted for wind energy from out-of-state. Under these purchased power agreements, Gulf and JEA receive renewable energy credits for the contracted energy.

Nuclear generation has steadily decreased since 2010, due to the decommissioning of DEF's Crystal River Unit 3. FPL is scheduled to potentially add new nuclear generation in 2027 and 2028, when FPL's Turkey Point Units 6 and 7 are estimated to come on-line. This could contribute an additional combined capacity of 2,200 MW zero-emissions generation capacity.

 $^{^{25} \}underline{http://www.psc.state.fl.us/ElectricNaturalGas/CustomerRenewableShowYear?folder=2015} \ .$

²⁶ http://www.psc.state.fl.us/ElectricNaturalGas/CustomerRenewableShowYear?folder=2014.

²⁷ http://www.psc.state.fl.us/ElectricNaturalGas/CustomerRenewableShowYear?folder=2015.

²⁸ <u>http://www.psc.state.fl.us/ElectricNaturalGas/CustomerRenewableShowYear?folder=2015</u>.

Section 4. Educating Florida's Consumers on Conservation

4.1 Commission Consumer Education Outreach

While the Commission has statutory authority to require conservation efforts by regulated utilities, as part of the agency's outreach program, the Commission complements utility efforts with its own conservation related activities. To effectively reach as many consumers as possible, the Commission's consumer education program uses a variety of platforms to share conservation information, including the Commission website, public events, brochures, press releases, E-Newsletters, and Twitter. Conservation information is also available through other governmental and utility websites. Section 4.2 lists related websites for state and federal agencies, investor-owned electric utilities, and local gas distribution companies to further assist consumers. Most of the data in this section covers January through September 2016, due to the report's publication date.

Triple E Award

For the third year, the Commission is recognizing small businesses for implementing Commission-approved, cost-effective conservation programs. Covering the state's five major geographic areas, each month the Commission presents its Triple E Award–for Energy Efficiency Efforts–to a local business that has accomplished superior energy efficiency by working with its local utility to help reduce its energy footprint. The Commission's Triple E Award recipients receive an award plaque, are highlighted through a press release issued statewide, and are featured under Hot Topics on the Commission's homepage, www.FloridaPSC.com.

Outreach

An assortment of information is available on the Commission website to help consumers save energy. According to Google Analytics, website page views for February through August 2016 totaled 677,724. One of the more popular website destinations is Find Your Utility. Chairman Julie Brown was instrumental in designing this website feature to provide consumers with contact information for Florida's utilities. Customers who are in a crisis situation and unable to pay their electric bills can tap into utilities' large network of social-service organizations and weatherization programs designed to lower utility bills and increase in-home comfort. To complement the website feature, the Commission's <u>A Guide to Utility Assistance in Florida</u> booklet is also available on the website. The publication provides a list of Florida's electric companies with their contact information for consumers' convenience.

The Commission also offers several energy conservation brochures to help consumers save energy. Brochures may be viewed and printed directly from the website, <u>FloridaPSC.com/publications</u>, ordered online, or requested by mail or phone. From January through August 2016, 35,865 brochures were mailed by request.

Newsletters

With its interactive design, the Commission's quarterly *Consumer Connection E-Newsletter* features current energy and water conservation topics, consumer tips, and general Commission information. Consumer tips highlighted through video and text in 2016 include *Prepare Your Air*

Conditioner for Summer, It's Hurricane Season, So Be Prepared!, and *Save Money During Spring Break.* The *Consumer Connection E-Newsletter* is available under Consumer Corner on the Commission's homepage and distributed to consumers via Twitter and by subscribing to the free newsletter <u>online</u>.

Chairman Julie Brown's monthly *FPSC Update* often features conservation topics and is distributed electronically to legislators, local government officials, and Florida Cabinet members. The *Update* is tweeted and also featured under Hot Topics and archived on the Commission's homepage.

National Consumer Protection Week

National Consumer Protection Week, highlighting consumer protection and education efforts, was important to the Commission's 2016 conservation education efforts. Chairman Julie Brown kicked off the 18th Annual *NCPW* (March 6-12, 2016) by hosting a press conference in Tallahassee to remind consumers of ways to avoid energy related fraud schemes and to curb high energy usage.

Also during the week, the Commission made presentations in Jacksonville, Tampa, St. Petersburg, and Panama City, showing consumers how to save money through energy and water conservation and how to avoid scams.

Older Americans Month

For the fifth year, the Commission participated in *Older Americans Month*, a national project celebrated each May to honor and recognize older Americans for their contributions to families, communities, and society. *Blaze A Trail* was this year's theme, and the Commission held 11 education sessions on ways to conserve energy and water, and on strategies to prevent becoming a victim of fraud at senior communities. The Commission also distributed brochures and publications at the Jacksonville Expo, where over 7,000 seniors attended.

Energy Awareness Month

Each October, the U.S. Department of Energy (DOE) sponsors National Energy Awareness Month to promote smart energy choices and highlight economic and job growth, environmental protection, and increased energy independence.

This year, the Commission highlighted Energy Awareness Month by recognizing an innovative solar array powering a 40,000 sq. ft. manufacturing facility—the only plant in Florida fully powered through net metering. This project's success stems from Florida using net metering to jump start solar generation in the state.

PSC Commissioner Jimmy Patronis joined Senator Denise Grimsley and Representative Halsey Beshears to tour the solar system that powers VizCo-US, the Visionary Company that produces plastic injection-molded drip pans, alarms, and pipe grips for water heaters. Jefferson County Commissioners also participated. The PSC's net metering rule allows solar power generators, such as VizCo, to tie into the power grid and gain credit for the power they contribute.

Community Events

FPSC Commissioners are active in communities around the state and regularly present energy conservation information to students at area schools, to seniors and low-income residents at local community centers, and to county and city businesses at meetings or other events.

Through ongoing partnerships with governmental entities, consumer groups, and many other service organizations, the Commission regularly distributes energy and water conservation materials. The Commission also actively looks for new community events, venues, and opportunities where conservation materials can be distributed and discussed with citizens.

Events where conservation information was shared during 2016 include:

- Senior Day at the Capitol
- Active Living Expo
- Jacksonville Senior Expo
- Second Harvest of the Big Bend
- Evergreen Missionary Baptist Church
- Trinity Café
- St. Petersburg Free Clinic
- Senior Awareness Day Pensacola
- Lunch and Learn Lake Jacksonville Senior Center
- Leon County Senior Outreach Appreciation Meeting
- Fraud Prevention Seminar Florida Department of Elder Affairs
- World Elder Abuse Awareness Day Tallahassee
- World Elder Abuse Awareness Day Melbourne
- Springfield Center
- Daniel D. Cantor Senior Center
- Sunrise Senior Center
- Southcentral/Southeast Focal Point Senior Center
- LifeStyle Enrichment Center of Ft. White
- Woodville Community Center
- 33rd Annual Children's Day Florida Museum of History
- Feeding Northeast Florida
- Feeding Northeast Florida Lunch with Luke
- LifeStyle Enrichment Center of Lake City
- Trinity Rescue Mission
- The Oaks at Riverview Senior Center
- Columbia County Public Library
- Bennie Furlong Senior Center
- Feeding Northeast Florida Christian Fellowship Ministries
- 7th Annual Southside Community Health & Fitness Fair Maranatha Seventh Day Adventist Church
- Suwanee County Health and Wellness Fair
- Panama City Beach Senior Center

- Bay County Area Council on Aging
- Lunch and Learn Bradfordville Senior Center
- Lynn Haven Senior Center
- El Beth-El Development Center
- Light In the World Community Day

Hearings and Customer Meetings

As an ongoing outreach initiative, the Commission supplies conservation brochures to consumers at Commission hearings and customer meetings across the state. From January through July 2016, Commission staff distributed information and addressed consumer questions at 20 public hearings and meetings. Consumers who file a complaint with the Commission about high electric or natural gas bills also receive conservation information.

Library Outreach Campaign

Each August, the Commission provides educational packets, including conservation materials, to Florida public libraries across the state for consumer distribution. The Commission's Library Outreach Campaign reached 583 state public libraries and branches in 2016. To reduce mailing and production costs, the Commission sent the materials via a CD that included a print-ready copy of brochures for easy reproduction. Following the Campaign, many libraries' requests for additional publications are filled.

Media Outreach

News releases are distributed to the media on major Commission decisions, meetings, and public events. The Office of Consumer Assistance & Outreach also issues news releases urging conservation. For instance, in a March news release, the Commission highlighted the federal government's *Fix a Leak Week* and shared several water conservation strategies. In May, the Commission issued a release for Older Americans Month outlining the importance of learning to conserve resources and save money.

Youth Education

The Commission emphasizes conservation education for Florida's young consumers. During 2016, the Commission continued to produce its student resource booklet--*Get Wise and Conserve Florida!*--to teach children about energy and water conservation. The booklet is distributed to all public libraries through the Library Outreach Program and is available at all Commission outreach events. The student resource book continues to be a favorite during senior events.

4.2 Related Websites

State Agencies and Organizations

Florida Public Service Commission – <u>http://www.floridapsc.com/</u> Florida Department of Environmental Protection – <u>http://www.dep.state.fl.us</u> The Office of Energy – <u>http://www.freshfromflorida.com/Divisions-Offices/Energy</u> Florida Solar Energy Center – <u>http://www.fsec.ucf.edu/</u> Florida Weatherization Assistance - <u>http://floridajobs.org/community-planning-and-</u> <u>development/community-services/weatherization-assistance-program</u>

Florida's Local Weatherization Agencies List – <u>http://floridajobs.org/community-planning-and-development/community-services/weatherization-assistance-program/contact-your-local-weatherization-office-for-help</u>

U.S. Agencies and National Organizations

U.S. ENERGY STAR Program – <u>http://www.energystar.gov/</u> U.S. Department of Energy – Energy Efficiency and Renewable Energy Information - <u>http://www.eere.energy.gov/</u> National Energy Foundation – <u>https://nef1.org/</u>

Florida's Electric Utilities Subject to FEECA

Florida Power & Light Company – <u>http://www.fpl.com/</u> Duke Energy Florida, LLC – <u>http://www.duke-energy.com/</u> Tampa Electric Company – <u>http://www.tampaelectric.com/</u> Gulf Power Company – <u>http://www.gulfpower.com/</u> Florida Public Utilities Company – <u>http://www.fpuc.com/</u> JEA – <u>http://www.jea.com/</u> Orlando Utilities Commission – <u>http://www.ouc.com/</u>

Florida's Investor-Owned Natural Gas Utilities

Peoples Gas System – <u>http://www.peoplesgas.com/</u> Florida City Gas – <u>http://www.floridacitygas.com/</u> Florida Public Utilities Company – <u>http://www.fpuc.com/</u> St. Joe Natural Gas Company – <u>http://www.stjoenaturalgas.com/</u> Sebring Gas System – <u>http://www.sebringgas.com/</u>

Appendix. FEECA Utilities' Conservation Programs

FEECA IOUs

A. Duke Energy Florida, LLC

Residential Programs

Home Energy Check

The Home Energy Check is a residential energy audit program that provides residential customers with an analysis of their energy consumption and educational information on how to reduce energy usage and save money.

Residential Incentive

The Residential Incentive Program provides incentives to residential customers for energy efficiency improvements in both existing and new homes.

Low-Income Weatherization Assistance Program

The Low-Income Weatherization Assistance Program works with the Florida Department of Economic Opportunity and local weatherization providers to deliver energy education, efficiency measures, and incentives to weatherize the homes of low-income families.

Neighborhood Energy Saver

The Neighborhood Energy Saver Program installs energy conservation measures, identified through an energy assessment, in the homes of customers in selected neighborhoods where at least 50 percent of households have incomes equal to or less than 200 percent of the poverty level established by the U.S. government.

Residential Energy Management

The Residential Energy Management Program uses direct control of customer equipment to reduce system demand during winter and summer peak capacity periods by temporarily interrupting select customer appliances.

Commercial/Industrial Programs

Business Energy Check

The Business Energy Check Program provides no-cost energy audits at non-residential facilities either over the phone or at the customer's facility.

Commercial Energy Management

The Commercial Energy Management Program uses direct control of customer equipment to reduce system demand during winter and summer peak capacity periods. The Commercial Energy Management Program was closed to new participants in 2000, but is still open for existing participants.

Better Business

Better Business is an umbrella efficiency program that provides incentives to existing C/I and government customers for HVAC, roof insulation, duct leakage and repair, demand-control ventilation, and cool roof coating.

Florida Custom Incentive

The Florida Custom Incentive Program provides incentives for individual custom projects, such as new construction measures or thermal energy storage systems, that are cost effective but not addressed by DEF's other programs.

Standby Generation

The Standby Generation Program is a demand control program that reduces DEF's system demand based on control of customer equipment. This program is available to C/I customers who have on-site generation capability and are willing to reduce demand on DEF's system when DEF requests for system reliability purposes.

Interruptible Service

Interruptible Service is a direct load control DSM program in which customers allow DEF to interrupt their electrical service during times of capacity shortages based on peak or emergency conditions. In return, customers receive a monthly bill credit.

Curtailable Service

Curtailable Service is an indirect load control DSM program in which customers contract to curtail all or a portion of their electricity demand during times of capacity shortages. In contrast to the Interruptible Service Program, the customer, instead of DEF, controls whether or not the customer's appliances are turned off during times of stress on the grid. In return, customers receive a monthly bill credit.

Research and Development and Pilot Programs

Technology Development

The Technology Development Program allows DEF to investigate technologies that hold promise for cost-effective demand reduction and energy efficiency. DEF will investigate variable capacity heat pump air conditioners, building automated energy efficiency and demand response, energy management circuit breakers, and more.

Qualifying Facility

The Qualifying Facility Program supports the interconnection and purchase of asavailable energy as well as firm energy and capacity from qualifying facilities including those that use renewable energy and distributed energy resources.

B. Florida Power & Light Company

Residential Programs

Residential Home Energy Survey

The Residential Home Energy Survey Program encourages implementation of recommended energy efficiency measures, even if they are not included in FPL's DSM programs. The Residential Home Energy Survey Program also identifies other FPL DSM programs that could be appropriate given residential customers' home layouts and electricity usage patterns.

Residential Ceiling Insulation

The Residential Ceiling Insulation Program encourages customers to improve their homes' thermal efficiency.

Residential Air-Conditioning

The Residential Air-Conditioning Program encourages customers to install highefficiency central air-conditioning systems.

Residential New Construction (BuildSmart)

The Residential New Construction Program encourages builders and developers to design and construct new homes that achieve BuildSmart certification and move towards ENERGY STAR qualifications.

Residential Low-Income

The Residential Low-Income Program assists low-income customers through state Weatherization Assistance Provider ("WAP") agencies and FPL conducted energy retrofits.

Residential Load Management (On Call)

The Residential Load Management Program allows FPL to turn off certain customerselected appliances using FPL-installed equipment during periods of extreme demand, capacity shortages, or system emergencies.

Commercial/Industrial Programs

Business Energy Evaluation

The Business Energy Evaluation Program educates customers on energy efficiency and encourages implementation of recommended practices and measures, even if these are not included in FPL's DSM programs. The Business Energy Evaluation is also used to identify potential candidates for other FPL DSM programs.

Business Lighting

The Business Lighting Program encourages customers to install high-efficiency lighting systems.

Business Heating, Ventilating, and Air Conditioning (HVAC)

The Business HVAC program encourages customers to install high-efficiency HVAC systems.

Business Custom Incentive

The Business Custom Incentive Program encourages customers to install unique highefficiency technologies not covered by other FPL DSM programs.

Business On Call

The Business On Call Program allows FPL to turn off customers' direct expansion central air-conditioning units using FPL-installed equipment during periods of extreme demand, capacity shortages, or system emergencies.

Commercial/Industrial Load Control (CILC)

The Commercial/Industrial Load Control Program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies. The CILC Program was closed to new participants as of 2000 but is available to participants who had entered into a CILC agreement as of March 19, 1996.

Commercial/Industrial Demand Reduction (CDR)

The Commercial/Industrial Demand Reduction Program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies. FPL installs a load management device at the customer's facility and provides monthly credits to customers. Unlike the CILC program, the CDR program is still open to new customers.

Research and Development and Pilot Programs

Conservation Research and Development (CRD)

Under Conservation Research and Development (CRD), FPL conducts research projects to identify, evaluate, and quantify the impact of new energy efficient technologies. FPL uses the findings to potentially add new energy efficient technologies to DSM programs.

Cogeneration & Small Power Production

The Cogeneration and Small Power Production Program facilitates the interconnection and administration of contracts for cogenerators and small power producers.

C. Florida Public Utilities Company

Residential Programs

Residential Energy Survey

In the Residential Energy Survey Program, FPUC provides the customer with specific whole-house energy efficiency recommendations. FPUC also provides customers with lists of blower-door test contractors who can check for duct leakage. Finally, FPUC provides the customer with a conservation kit including 2 LED light bulbs and more.

Residential Heating and Cooling Efficiency Upgrade

First, the Residential Heating and Cooling Upgrade Program incentivize customers operating inefficient heat pumps and air conditioners to replace them with more efficient units. Also, the program incentivizes customers with resistance heating to install a new heat pump. Finally, the program incentivizes customers who are replacing heat pumps or air conditioners that have reached the end of their lives to replace them with more efficient heat pump or air conditioners than are required by code.

Commercial Programs

Commercial Energy Consultation

In the Commercial Energy Consultation Program, FPUC energy conservation representatives conduct commercial site visits to assess the potential for applicable DSM programs, educate customers about FPUC's commercial DSM programs, and more.

Commercial Heating and Cooling Efficiency Upgrade

The Commercial Heating and Cooling Upgrade Program provides rebates to small commercial customers (customers with a maximum of 5 ton units) only if the customers install a high-efficiency central air conditioner or heat pump with a minimum 15 SEER.

Commercial Reflective Roof

The Commercial Reflective Roof Program provides rebates to non-residential customers who convert their existing roof to a cool roof or who install a new cool roof on an existing or new building. The rebates cover up to 25 percent of the added upfront cost of building a cool roof compared to an alternative roof.

Commercial Chiller Upgrade

The Commercial Chiller Upgrade Program offers customers an incentive of up to \$175kW of savings above minimum efficiency levels.

Educational and Research Programs

Low-Income Energy Outreach

The Low-Income Energy Outreach Program partners with Department of Economic Opportunity approved Low-Income Weatherization Program operators to offer Residential Energy Surveys, distributing energy conservation materials, and more.



Conservation Demonstration and Development

The Conservation Demonstration and Development Program researches energy efficiency and conservation projects to identify, develop, demonstrate, and evaluate promising enduse energy efficient technologies across a wide variety of applications.

D. Gulf Power Company

Residential Programs

Residential Energy Audit and Education

The Residential Energy Audit and Education Program is the primary educational program to help customers improve the energy efficiency of their new or existing home by providing energy conservation advice and information that encourages the implementation of efficiency measures and behaviors resulting in electricity bill savings.

Community Energy Saver (Low-Income)

The Community Energy Saver Program installs energy conservation measures in the homes of low-income families at no cost to the customers. The program also educates families on behavioral changes to save money by decreasing energy use.

Residential Custom Incentive

The Residential Custom Incentive Program aims to increase energy efficiency in the residential rental property sector. The program promotes the installation of efficiency measures available through other programs, such as HVAC maintenance and quality installation, high performance windows, and reflective roofing. As suitable, the program has other incentives to surmount the split-incentive barrier in a landlord/renter situation.

HVAC Efficiency Improvement

The HVAC Efficiency Improvement Program aims to increase energy efficiency and improve HVAC cooling system performance for new and existing homes. Gulf increases efficiency through HVAC maintenance, duct repair, and HVAC quality installation.

Residential Building Efficiency

The Residential Building Efficiency Program is an umbrella efficiency program for existing and new residential customers to install eligible equipment such as high performance windows, reflective roof, and ENERGY STAR window air conditioners. The goals are to increase customer demand for energy efficient technologies and to create long-term energy savings and peak demand reduction.

Energy Select

The Energy *Select* Program gives customers a way to manage their energy consumption by programming their heating and cooling systems and major appliances, such as electric water heaters and pool pumps, to respond automatically to prices that vary during the day and by season in relation to Gulf's cost of producing or purchasing energy.



Residential Service Time of Use Pilot

The Residential Service Time of Use Pilot Program provides residential customers the opportunity to use customer-owned equipment to respond automatically and take advantage of a variable pricing structure with a critical peak component. The pilot will be offered to 400 residential customers. The goal is to measure customers' response, with customer owned equipment, to a variable electricity price.

Commercial Programs

Commercial/Industrial Audit

The Commercial/Industrial Audit Program provides advice to Gulf's existing C/I customers on how to reduce energy consumption. The program ranges from an Energy Analysis Audit and walk-through surveys to a Technical Assistance Audit and computer programs that simulate options for very large, energy-intensive customers.

Commercial HVAC Retrocommissioning

The Commercial HVAC Retrocommissioning program offers retrocommissioning at a reduced cost for qualifying installations by C/I customers. Retrocommissioning is a process of identifying suboptimal performance in a facility's systems and replacing the outdated equipment.

Gulf's retrocommissioning program uses an independent computerized quality control process to diagnose the performance of HVAC cooling units (air conditioners, heat pumps, direct expansion, or geothermal cooling and heating) operating in commercial buildings. Then, Gulf works to improve or replace any suboptimal performing units in order to get closer to full efficiency.

Commercial Building Efficiency

The Commercial Building Efficiency Program is an umbrella efficiency program for C/I customers to encourage the installation of high-efficiency equipment in order to reduce energy and demand. The high-efficiency equipment is focused on commercial geothermal heat pumps, ceiling/roof insulation, and reflective roofs.

Commercial/Industrial Custom Incentive

The Commercial/Industrial Custom Incentive Program first offers energy efficient enduser equipment to C/I customers. The C/I Custom Incentive Program also offers energy services such as comprehensive audits, design, and construction of energy conservation projects. Covered projects include demand reduction or energy improvement retrofits that are beyond the scope of other programs.

Research and Development Programs

Conservation Demonstration and Development

The Conservation Demonstration and Development Program is an umbrella program for the identification, development, and evaluation of end-use energy efficient technologies. One example is the Tesla Powerwall Demand Response (DR) project, which will assess



the impact of battery storage in terms of performance, reliability, and economic return on investment. Another example is the Tesla Powerfall Demand Photovoltaic project.

E. Tampa Electric Company

Residential Programs

Residential Energy Audits

The Residential Energy Audits Program includes a walk-through free energy check, a customer assisted energy audit, a computer assisted paid energy audit, and a building energy ratings system (BERS).

Residential Ceiling Insulation

The Residential Ceiling Insulation Program offers rebates to existing residential customers to install additional ceiling insulation in existing homes.

Residential Duct Repair

The Residential Duct Repair Program encourages residential customers to repair leaky duct work of central air conditioning systems in existing homes.

Residential Electronically Commutated Motors (ECM)

The Residential Electronically Commuted Motors (ECM) Program encourages residential customers to replace their existing HVAC air handler motors with more efficient ECMs.

Energy Education, Awareness, and Agency Outreach

The Energy Education, Awareness, and Agency Outreach Program engages and educates groups of customers and students on energy efficiency in an organized setting. Also, participants receive an energy savings kit with energy saving devices and information.

ENERGY STAR for New Homes

The ENERGY STAR for New Homes Program incentivizes residential customers to build homes that qualify for the ENERGY STAR award by achieving energy efficiency levels greater than current Florida building code baseline practices.

Residential Heating and Cooling

The Residential Heating and Cooling Program offers rebates to residential customers for installing high-efficiency heating and cooling equipment in existing homes.

Neighborhood Weatherization (Low-Income)

The Neighborhood Weatherization Program provides for the installation of energy efficient measures for qualified low-income customers.

Residential Price Responsive Load Management (Energy Planner)

The Residential Price Responsive Load Management (Energy Planner) Program reduces weather-sensitive loads through an innovative price responsive rate. The price responsive
rate encourages residential customers to make behavioral or equipment usage changes by pre-programming HVAC, water heating, and pool pumps.

Residential Wall Insulation

The Residential Wall Insulation Program offers rebates to existing residential customers to install additional wall insulation in existing homes.

Residential Window Replacement

The Residential Window Replacement Program offers rebates to existing residential customers to install window upgrades in existing homes.

Commercial Programs

Commercial/Industrial Energy Audits

In the C/I Energy Audits Program, C/I customers can receive more limited free energy audits or comprehensive paid energy audits.

Commercial Ceiling Insulation

The Commercial Ceiling Insulation Program incentivizes C/I customers to install additional ceiling insulation in existing commercial buildings.

Commercial Chiller

The Commercial Chiller Program offers rebates to C/I customers for installing high efficiency chiller equipment.

Cogeneration

The Cogeneration Program incentivizes large industrial customers with waste heat or fuel resources to use their onsite energy to avoid fuel waste and install electric generating equipment. The large industrial customers may sell their surplus electric generation to TECO.

Conservation Value

The Conservation Value Program offers rebates to C/I customers to invest in energy conservation measures that are not in other C/I programs.

Commercial Cool Roof

The Commercial Cool Roof Program encourages C/I customers to install a cool roof system above conditioned spaces.

Commercial Cooling

The Commercial Cooling Program encourages C/I customers to install high efficiency direct expansion commercial air conditioning cooling equipment.

Demand Response

The Demand Response Program incentivizes C/I customers to reduce electricity demand at certain peak times.



Commercial Duct Repair

The Commercial Duct Repair Program encourages C/I customers to repair leaky ductwork of central air-conditioning systems in existing C/I facilities.

Commercial Electronically Commutated Motors (ECM)

The Commercial Electronically Commutated Motors (ECM) Program encourages C/I customers to replace air handler motors or refrigeration fan motors with ECMs.

Industrial Load Management (GSLM 2&3)

The Industrial Load Management (GSLM 2&3) Program incentivizes large industrial customers to allow TECO to interrupt part of or their entire electrical service during periods of peak stress on the grid.

Lighting Conditioned Space

The Lighting Conditioned Space Program encourages C/I customers to invest in more efficient lighting technologies in existing conditioned areas of C/I facilities.

Lighting Non-Conditioned Space

The Lighting Non-Conditioned Space Program encourages C/I customers to invest in more efficient lighting technologies in existing non-conditioned areas of C/I facilities.

Lighting Occupancy Sensors

The Lighting Occupancy Sensors Program encourages C/I customers to install occupancy sensors to control C/I lighting systems.

Commercial Load Management

The Commercial Load Management Program incentivizes C/I customers to allow TECO to control weather-sensitive heating, cooling, and water heating systems to reduce the associated weather-sensitive peak demand.

Refrigeration Anti-Condensate Control

The Refrigeration Anti-Condensate Control Program encourages C/I customers to install anti-condensate equipment sensors within refrigerated door systems.

Standby Generator

The Standby Generator Program incentivizes C/I customers to use any emergency electrical generation capacity they have in order to reduce weather-sensitive peak demand on the grid.

Thermal Energy Storage

The Thermal Energy Storage Program encourages C/I customers to install an off-peak air conditioning system.

Commercial Wall Insulation

The Commercial Wall Insulation Program encourages C/I customers to install wall insulation in existing C/I structures.



Commercial Water Heating

The Commercial Water Heating Program encourages C/I customers to install high efficiency water heating systems.

Research and Development

DSM Research and Development (R&D)

The DSM Research and Development Program allows TECO to explore DSM measures that have insufficient data on cost-effectiveness and the impact on TECO's ratepayers.

Renewable Energy

The Renewable Energy Program delivers renewable energy options to TECO's customers through program administration, renewable electricity generation, evaluation of potential new renewable sources, and market research.

DRAFT

Non-IOU FEECA Utilities

A. JEA

Residential Programs

Residential Energy Audit

In the Residential Energy Audit Program, JEA examines homes, educates customers, and makes recommendations on low-cost or no-cost energy-saving practices and measures.

Residential Solar Water Heating

The Residential Solar Water Heating Program pays a financial incentive to customers to encourage the use of solar water heating technology.

Residential Solar Net Metering

The Residential Solar Net Metering Program promotes the use of PV by purchasing excess electricity from residential customers who have PV.

Neighborhood Efficiency (Low-Income)

The Neighborhood Efficiency Program offers education concerning the efficient use of energy and water as well as the direct installation of an array of energy and water efficiency measures at no cost to income qualified customers.

Residential Efficiency Upgrade

The Residential Efficiency Upgrade Program provides incentives to encourage the use of high efficiency HVAC and water heating. This is one of the DSM programs that JEA offers which has not been approved by the Commission and is not part of FEECA. Nevertheless, this program creates demand and energy savings.

Energy Efficient Products

The Energy Efficient Products Program provides incentives to encourage the use of high efficiency lighting and efficient appliances. This is one of the DSM programs that JEA offers which has not been approved by the Commission and is not part of FEECA.

Residential New Build

The Residential New Build Program promotes the use of high efficiency HVAC, water heating, lighting, and appliances in the new construction market. This is one of the DSM programs that JEA offers which has not been approved by the Commission and is not part of FEECA. Nevertheless, this program creates demand and energy savings.

Commercial Programs

Commercial Energy Audit

In the Commercial Energy Audit Program, JEA examines businesses, educates customers, and makes recommendations on low-cost or no-cost energy-saving practices.



Commercial Solar Net Metering

The Commercial Solar Net Metering Program promotes the use of PV by purchasing excess electricity from commercial customers who have PV.

Commercial Prescriptive

The Commercial Prescriptive Program provides incentives to encourage the use of high efficiency HVAC, lighting, cooking, and water heating products. This is one of the DSM programs that JEA offers which has not been approved by the Commission and is not part of FEECA. Nevertheless, this program creates demand and energy savings.

Small Business Direct Install

The Small Business Direct Install Program promotes the use of high efficiency HVAC, lighting, water heating, and appliances in the small business sector. This is one of the DSM programs that JEA offers which has not been approved by the Commission and is not part of FEECA. Nevertheless, this program creates demand and energy savings.

Custom Commercial

The Custom Commercial Program promotes the use of custom efficiency measures based on specific applications for each customer. This is one of the DSM programs that JEA offers which has not been approved by the Commission and is not part of FEECA.

B. Orlando Utilities Commission

Residential Programs

Residential Home Energy Survey

The Residential Home Energy Survey Program consists of three measures: a Residential Energy Walk-Through Survey, a Residential Energy Survey DVD, and an interactive Online Energy Survey.

Residential Duct Repair/Replacement Rebate

The Residential Duct Repair/Replacement Rebate Program provides up to a \$160 rebate to encourage customers to repair leaking ducts on existing systems.

Residential Ceiling Insulation Upgrade Rebate

The Residential Ceiling Insulation Upgrade Rebate Program is offered to residential customers to encourage them to upgrade their attic insulation. Customers receive \$0.05 per square foot for upgrading their attic insulation up to R-30. If OUC verifies that existing insulation is R-11 or less, the rebate rises to \$0.14 per square foot.

Residential Window Film/Solar Screen Rebate

The Residential Window Film/Solar Screen Rebate Program encourages solar shading on windows. Customers receive a rebate of \$1 per square foot for installing solar shading film with a shading coefficient of 0.5 or less on east, west, and south facing windows.



Residential High Performance Windows Rebate

The Residential High Performance Windows Rebate Program encourages customers to install windows that minimize heating, cooling, and lighting costs. Customers receive a \$2.00 rebate per square foot for the purchase of windows rated ENERGY STAR.

Residential Efficient Electric Heat Pump Rebate

The Residential Efficient Electric Heat Pump Rebate Program provides rebates to customers in existing homes who install heat pumps having a seasonal energy efficiency ratio (SEER) of 15.0 or higher. Depending on the SEER rating and the capacity of the new heat pump, the rebate can be a bill credit ranging from \$80 to \$1,275.

Residential New Home Rebate

The Residential New Home Rebate Program offers rebates for cool/reflective roofs, block wall insulation, ceiling insulation upgrades to R-38, heat pumps, ENERGY STAR washing machines, ENERGY STAR heat pump water heaters, and solar water heaters.

Residential Efficiency Delivered (Low-Income)

The Residential Efficiency Delivered Program is income based and provides up to \$2,000 of energy and water efficiency upgrades based on the needs of the residential customer's home. An OUC Conservation Specialist visits the home, performs a home survey, and recommends which home improvements have the most potential of lowering utility bills.

Commercial Programs

Commercial Energy Audits

The Commercial Energy Audit Program includes a free survey consisting of a physical walk-through inspection of the commercial facility performed by experienced energy experts. Following the inspection, the customer receives a written report.

Commercial Efficient Electric Heat Pump Rebate

The Commercial Efficient Electric Heat Pump Rebate Program provides rebates to qualifying customers in existing buildings who install heat pumps having a seasonal energy efficiency ratio (SEER) of 15.0 or higher. Depending on the SEER rating and the capacity of the new heat pump, the rebate can be a bill credit ranging from \$80 to \$1,275.

Commercial Duct Repair Rebate

The Commercial Duct Repair Rebate Program provides rebates of 100 percent of the cost, up to \$160, when qualifying customers have an existing central air conditioning system of 5.5 tons or less. Then, customers must seal ducts with mastic and fabric tape or Underwriters Laboratory (UL) approved duct tape.

Commercial Window Film/Solar Screen Rebate

The Commercial Window Film/Solar Screen Rebate Program aims to reflect heat during hot summer days and retain heat on cool winter days. The program provides rebates of \$1 per square foot for window tinting and solar screening with a solar heat gain coefficient (SHGC) of 0.44 or shading coefficient of 0.5 or less.



Commercial Ceiling Insulation Rebate

The Commercial Ceiling Insulation Rebate Program aims to increase a building's resistance to heat loss and gain. Participating customers receive \$0.05 per square foot for upgrading their attic insulation up to R-30. If OUC verifies that the existing insulation is R-11 or less, OUC will pay a rebate of \$0.14 per square foot.

Commercial Cool/Reflective Roof Rebate

The Commercial Cool/Reflective Roof Rebate Program aims to reflect the sun's rays and lower roof surface temperature while increasing the lifespan of the roof. OUC provides rebates of \$0.14 per square foot of ENERGY STAR cool/reflective roofing that has an initial solar reflectance greater than or equal to 0.70.

Attachment 3



Public Service Commission

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

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

- **DATE:** November 18, 2016
- **TO:** Braulio L. Baez, Executive Director
- **FROM:** Greg Fogleman, Public Utilities Supervisor, Office of Telecommunications Catherine S. Beard, Public Utility Analyst II, Office of Telecommunications Sakina Deas, Research Assistant, Office of Telecommunications Kiwanis L. Curry, Public Utility Analyst IV, Office of Telecommunications Beth W. Salak, Director, Office of Telecommunications Cynthia L. Muir, Director, Office of Consumer Assistance & Outreach
- **RE:** 2016 Annual Lifeline Report regarding the Number of Customers Subscribing to Lifeline Service and the Effectiveness of Any Procedures to Promote Participation.

Critical Information: ACTION IS NEEDED – Please place on the November 29, 2016, Internal Affairs agenda. Commission approval of the Lifeline Report draft report is sought. The 2016 Lifeline Final Report is due to the Governor, President of the Senate, and Speaker of the House by December 31, 2016.

Staff is seeking approval of the draft 2016 Annual Lifeline Report regarding the number of customers subscribing to Lifeline Service and the effectiveness of any procedures to promote participation. Section 364.10(2)(h), Florida Statutes, requires the FPSC to provide this report to the Governor, President of the Senate, and Speaker of the House of Representatives by December 31 each year. The report details regulatory actions impacting the Lifeline Program and Lifeline Awareness promotions in Florida. Commission Approval of the Lifeline draft report is sought.

As of June 30, 2016, 852,255 eligible customers participated in the Florida Lifeline program. The attached draft report has been prepared to fulfill the Florida legislative requirement. Staff is seeks approval of the draft of the 2016 annual Lifeline Report.

Attachment cc: Mark Futrell, Deputy Executive Director, Technical



A report to the Governor President of the Senate Speaker of the House of Representatives

FLORIDA

LIFELINE

ASSISTANCE

Number of Customers Subscribing to Lifeline Service And the Effectiveness of Procedures to Promote Participation

December 2016

FLORIDA FLORIDA ASSISTANCE

Number of Customers Subscribing to Lifeline Service And the Effectiveness of Procedures to Promote Participation

> Office of Telecommunications Office of Consumer Assistance & Outreach

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List of Acronyms

CFR	Code of Federal Regulations
DCF	Department of Children and Families
ETC	Eligible Telecommunications Carrier
FCC	Federal Communications Commission
FPSC	Florida Public Service Commission
NCPW	National Consumer Protection Week
NLAD	National Lifeline Accountability Database
OPC	Office of Public Counsel
SNAP	Supplemental Nutrition Assistance Program (formerly Food Stamps)
TCA	Temporary Cash Assistance
USAC	Universal Service Administrative Company

I. Executive Summary

In accordance with Section 364.10, Florida Statutes, the Florida Public Service Commission (FPSC) has oversight over the Florida Lifeline Program. The federal Universal Service Program provides the funding in Florida for the Lifeline Program and establishes certain rules. The Lifeline Program is designed to enable low-income households to obtain and maintain telephone service. The Lifeline Program offers qualifying households a minimum \$9.25 discount on their monthly phone bills, or a free Lifeline cell phone and monthly minutes from certain wireless providers. This report presents Lifeline participation data for the July 2015 through June 2016 program year, and evaluates procedures put in place to strengthen and streamline the Lifeline Program.

In Florida, 852,255 eligible households participated in the Lifeline Program as of June 30, 2016. This equates to approximately one of every eleven Florida households participating in the Lifeline Program.¹ Lifeline assistance participation includes the involvement of the FPSC, the Florida Department of Children and Families (DCF), the Florida Office of Public Counsel (OPC), the Florida Department of Education and other state agencies that provide benefits to persons eligible for Lifeline service.²

Half of all Lifeline-eligible Florida households are receiving Lifeline assistance. The Supplemental Nutrition Assistance Program (SNAP) continues to be the largest qualifying program for Lifeline assistance in Florida. Based upon June 2016 SNAP participants, the number of Lifeline eligible households decreased by 14.8 percent compared to last year.³

The FPSC participated in events to promote and provide consumers with information regarding eligibility. For example, the FPSC was active in March during the National Consumer Protection Week. FPSC Chairman Julie I. Brown kicked off the week by hosting a press conference in Tallahassee at America's Second Harvest of the Big Bend.

The FPSC continues to focus on improving the enrollment process, while eliminating any waste, fraud, and abuse in the program. Specific enrollment initiatives include the following:

- FPSC Lifeline Coordinated Online Application Process
- FPSC/DCF Coordinated Lifeline Enrollment
- Annual Recertification Procedures
- DCF Certification/Verification Web Services Interface
- Lifeline Work Group Meetings
- National Lifeline Accountability Database

In addition, the Federal Communications Commission (FCC) revised its rules related to the Lifeline Program with some portions effective as early as December 2, 2016.

¹ Florida Legislature Office of Economic and Demographic Research, Demographic Estimating Conference, Florida Households Jul. 2016: 7,914,312, <u>http://edr.state.fl.us/Content/conferences/population/ ConferenceResults.pdf</u>, accessed Sept. 16, 2016, p. T-2.

² Section 364.10(2)(g)1., Florida Statutes.

³ USDA, Supplemental Nutrition Assistance Program: Households Participating, Florida SNAP households for Jun. 2016: 1,712,005, <u>http://www.fns.usda.gov/ sites/default/files/pd/30SNAPcurrHH.pdf</u>, accessed Sept. 26, 2016.

II. Background

The FPSC is required to report to the Governor, the President of the Senate, and the Speaker of the House of Representatives each year on the number of customers subscribing to Lifeline service and the effectiveness of procedures to promote participation in the program. This report is prepared pursuant to the requirements contained in Section 364.10, Florida Statutes.

In Florida, if an applicant uses the electronic Lifeline Coordinated Enrollment Process⁴ to apply for Lifeline, the process will confirm if the applicant is currently participating in the Medicaid, SNAP or Temporary Cash Assistance (TCA)⁵ programs. If a program other than Medicaid, SNAP, or TCA, is used for certification, the customer must provide documentation of participation from the administering agency, which could be the Florida Department of Education (free school lunch program), the Social Security Administration (Supplemental Security Income), a county-level agency (Low-Income Home Energy Assistance Plan or Section Eight Housing), or the Bureau of Indian Affairs for documentation.

If a Lifeline applicant chooses to apply for Lifeline directly with an eligible telecommunications carrier (ETC), the ETC can access the DCF web services⁶ in real-time to confirm program participation for Medicaid, SNAP, and TCA. Certification and verification in Florida can be accomplished using this process if the applicant or existing Lifeline customer participates in the Medicaid, SNAP, or TCA programs which are administered by the DCF.

The National Lifeline Accountability Database (NLAD), which is maintained by the Universal Service Administrative Company (USAC),⁷ is designed to help carriers identify and resolve duplicate claims for Lifeline Program supported services and prevent future duplicates. This database provides a means for carriers and state commissions to check, on a real-time and nationwide basis, if the household is already receiving a Lifeline Program supported service.

In April 2016, the FCC released an Order to further reform the Lifeline Program.⁸ The FCC's Order takes a variety of actions to encourage more Lifeline providers to deliver newly supported broadband services. Over the next five years, FCC plans to shift support from voice-only services to services that at least include a broadband component.

⁴ The electronic Lifeline coordinated enrollment process was developed by the FPSC and DCF to allow an applicant for Medicaid, SNAP, or TCA to request and receive Lifeline assistance after being approved for the DCF program. ⁵ Nationally known as Temporary Assistance for Needy Families (TANF).

⁶ The Web services interface allows Florida ETCs a secure gateway into the DCF computer to verify that a Lifeline customer is participating in the Medicaid, SNAP, or TCA programs administered by DCF. The ETC enters the person's first and last name, date of birth, and last four digits of the person's social security number. The DCF computer responds as to whether the person currently participates in one of the DCF programs without identifying the program because of confidentiality. An ETC must pre-register with DCF to use the Web services interface to ensure security is maintained.

⁷ The Universal Service Administrative Company (USAC) is an independent, not-for-profit corporation designated by the Federal Communications Commission as the administrator of the Universal Service Fund. USAC collects contributions from telecommunications carriers and administers support programs designed to help communities across the country secure access to affordable telecommunications services.

⁸ FCC 16-38, WC Docket No. 11-42, Lifeline Reform and Modernization, Third Report and Order, released April 27, 2016, <u>https://apps.fcc.gov/edocs_public/attachmatch/FCC-16-38A1.pdf</u>, accessed on September 26, 2016.

While the explicit support of broadband is an important aspect of the FCC's reform, the aspects that impact Florida's program relate to customer eligibility, implementation of a national verifier, and reductions in support for voice-only services. As part of the expansion to support broadband through the Lifeline Program, the FCC also established minimum service standards for broadband and mobile voice services to ensure those services meet the needs of consumers.

III. Lifeline Participation

Currently, FCC rules allow a \$9.25 maximum reimbursement per Lifeline-eligible customer per month from USAC to a participating Lifeline carrier. The additional tier of support, available only to eligible subscribers living on tribal lands, provides a credit up to \$25.00 per month.

Florida Transitional Lifeline Assistance requires that ETCs offer former Lifeline customers, who are no longer eligible, a 30 percent discount off the residential basic local service rate. The customers are eligible to receive the discount for one year from the date the customer ceases to be qualified for Lifeline.⁹

Program-Based

Customers can qualify for Lifeline service in Florida by enrollment in any one of the following programs:¹⁰

- Food Assistance (SNAP)
- Medicaid
- Federal Public Housing Assistance (Section 8)
- Supplement Security Income
- Low-Income Home Energy Assistance Program
- Temporary Cash Assistance (TCA)
- National School Lunch Program Free Lunch
- Bureau of Indian Affairs Programs: Tribal Temporary Assistance to Needy Families, Head Start Subsidy and National School Lunch Program

Federal changes to the list of qualifying programs are effective on December 2, 2016. The Veterans Pension program will be added and Low-Income Home Energy Assistance, TCA, and the National School Lunch programs will no longer be included.

Income-Based

In addition to the program-based criteria, customers with annual incomes up to 150 percent of the Federal Poverty Guidelines may be eligible to participate in the Florida Lifeline Program.¹¹ The Federal Poverty Guidelines used are updated annually by U.S. Department of Health of Human Services. The 2016 Federal Poverty Guidelines are shown in Attachment A.¹² The Office of Public Counsel (OPC) certifies customer eligibility under the income-based criteria for customers requesting to be enrolled in the Lifeline Program for the three major wireline companies designated as ETCs.¹³ The OPC also performs income certification for wireless ETCs

⁹ Section 364.105, Florida Statutes.

¹⁰ Rule 25-4.0665(1) and (2), Florida Administrative Code.

¹¹ See Section 364.10(2)(a), Florida Statutes.

¹² Department of Health and Human Services, Annual Update of the Department of Health and Human Service Poverty Guidelines. See Federal Register Notice, January 25, 2016.

¹³ The three major wireline companies are AT&T, CenturyLink, and Frontier Florida (formally Verizon Florida).

who have chosen to do so.¹⁴ Effective on December 2, 2016, the FCC Reform Order allows income based eligibility to be up to 135 percent of the Federal Poverty Guidelines.¹⁵

Participation

The number of subscribers enrolled in Lifeline was 852,255 as of June 30, 2016, a 2.3 percent increase from the number of subscribers last year. Figure 1 shows the number of Lifeline subscribers from June 2009 through 2016. In 2013, the decrease in subscribership was largely attributable to the FCC rules adopted in 2012 which require annual recertification of every subscriber receiving Lifeline credits. Many customers failed to respond to the ETCs' recertification requests and were removed from the program. In 2016, subscribership grew as a result of overall increased demand for wireless Lifeline service. In contrast, wireline companies experienced an overall decline in Lifeline subscribers. Finally, the success of the National Lifeline Accountability Database, which prevents Lifeline subscribers from receiving more than one Lifeline credit per household, continues to be a factor.



Source: Industry responses to FPSC data requests (2009-2016)

For fiscal year ending June 2016, there was an increase in subscribership of 18,829 households, or 2.3 percent. Lifeline eligible households decreased by 299,161, or 14.8 percent, resulting in the participation rate increasing to 49.8 percent.¹⁶ This was an increase of 8.4 percentage points compared to 2015. Figure 2 shows participation rates in Florida households from June 2013 through June 2016.¹⁷ Considering the number of households which are eligible to receive

¹⁴ The wireless companies are SafeLink, T-Mobile and Virgin Mobile/Assurance Wireless.

¹⁵ FCC 16-38, WC Docket No. 11-42, Lifeline Reform and Modernization, Third Report and Order, released April 27, 2016, <u>https://apps.fcc.gov/edocs_public/attachmatch/FCC-16-38A1.pdf</u>, accessed on September 26, 2016.

¹⁶ USDA, Supplemental Nutrition Assistance Program: Number of Households Participating, data as of September 9, 2016, <u>http://www.fns.usda.gov/sites/default/files/pd/30SNAPcurrHH.pdf</u>, accessed on September 26, 2016.

¹⁷ Historical data in figure 2 has been corrected to remove a small number of resold lines that were counted twice.

Lifeline in Florida and the current participation rate, these numbers continue to demonstrate the need for the Lifeline Program.

Lifeline Participation Rate in Eligible Florida Households for 2013-2016						
Year	Lifeline Enrollment	Eligible Households	Percent Participation Rate			
June 2013	917,467	1,952,890	47.0%			
June 2014	957,533	1,930,106	49.6%			
June 2015	833,426	2,011,166	41.4%			
June 2016	852,255	1,712,005	49.8%			

Figure 2

Source: U.S. Department of Agriculture

IV. Lifeline Providers

As part of the Telecommunications Act of 1996, Congress allows state commissions to designate carriers as ETCs if they meet certain requirements.¹⁸ Conversely, a state commission also has the authority to rescind the ETC status of any ETC designated by it that does not follow the requirements of the Lifeline Assistance Program. Currently, the FPSC only designates wireline ETC applications, while wireless ETC applications are conducted by the FCC.¹⁹

To qualify as an ETC, a common carrier must offer services that are supported by federal universal service support mechanisms.²⁰ The carrier must advertise the availability of such services and charges. These services must be offered either using its own facilities or a combination of its own facilities and another carrier's resold service.

The FPSC has determined that before designating a telecommunications carrier as an ETC, it should make an affirmative determination that such designation is in the public interest, regardless of whether the applicant seeks designation in an area served by a rural or non-rural carrier.²¹ A company applying and qualifying for designation as an ETC must demonstrate good management and legitimate business practices to successfully administer the Lifeline Program.²²

In 2011, the FCC took a technology-neutral approach and determined that ETCs can use any platform to provide voice service. Figure 3 shows the 18 companies which had ETC status and participated in the Lifeline Program in Florida as of June 30, 2016. Attachment B represents the historic enrollment figures for the Lifeline Program listed by each of the ETCs.

Access Wireless (i-wireless)	ITS Telecommunications		
Assurance Wireless (Virgin Mobile)	Knology of Florida, Inc. (WOW!)		
AT&T Florida (AT&T)	NEFCOM		
CenturyLink	Quincy Telephone Company (TDS)		
Cox Florida Telecom, LP	SafeLink Wireless (TracFone)		
FairPoint Communications	Smart City Telecom		
Frontier Communications of the South	Tele Circuit Corporation		
Frontier Florida, LLC (formerly Verizon)	T-Mobile Wireless		
Global Connection Inc.	Windstream Florida, Inc.		

Figure 3 ETCs Participating in Florida Lifeline Program

Source: Industry responses to 2016 FPSC data requests

¹⁸ Section 214(e)(2) of the Telecommunications Act of 1996.

¹⁹ The Florida 2011 Legislature (HB 1231), removed the FPSC authority to designate ETC wireless providers. Effective July 1, 2012, wireless providers must directly apply for Florida ETC designation with the FCC.

 $^{^{20}}$ 47 C.F.R. §54.101(a)(1); Those services include: (1) voice grade access to the public switched network, (2) minutes of use for local service provided at no additional charge to end users, (3) toll limitation to qualifying low-income consumers, and (4) access to the emergency services 911 and enhanced 911 services.

²¹ Docket No. 120165-TP, Order No. PSC-12-0500-PAA-TP, issued September 28, 2012.

²² 47 C.F.R. §54.201(h).

Prior to August 15, 2016, resellers could sell Lifeline discounted service from an ETC through a resale agreement. The ETC would receive the support from USAC, and reduce the price of service to the reseller by the corresponding amount. The FCC's 2015 Lifeline Reform Order amended the Lifeline rules to eliminate Lifeline reimbursement for non-ETC resellers provisioning service through resale agreements out of concern of possible waste and abuse of program funds.²³ As a result, some affected carriers have left the Florida market. The FCC did provide a way for affected carriers to become an ETC and provide Lifeline service by filing a compliance plan that addresses the FCC's concerns regarding potential waste and abuse of the program. Specifically, such non-facilities based carriers must file a plan that demonstrates:

- 1) Commitment and ability to provide the supported services throughout the designated area;
- 2) Ability to remain functional in emergency situations;
- 3) Ability to satisfy consumer protection and service quality standards;
- 4) Provision of local usage comparable to that offered by the incumbent local exchange companies (ILEC).

As of July 1, 2011, the FPSC no longer has authority to designate wireless ETCs in the State of Florida. Wireless ETC applications for Florida are now filed directly with the FCC. Figure 4 shows the 40 Florida ETC Wireless petitions pending at the FCC.

Pending Wireless ETC Designation Petitions at FCC as of June 2016				
Airvoice Wireless	Mobile Net POSA			
American Broadband	NewPhone Wireless			
Amerimex	Nexus Communications			
AmTel	Odin Wireless			
Assist Wireless	Pinnacle Telecommunications			
Birch Communications, Inc.	PlatinumTel Communications			
Blue Jay Wireless	Q Link Wireless			
Boomerang Wireless	Sage Telecom Communications, LLC			
Budget PrePay, Inc.	SelecTel Wireless			
Cintex Wireless	TAG Mobile			
Consumer Cellular	TNT Wireless			
EZ Reach Mobile	Tele Circuit Network			
FedLink Wireless	Telrite			
Free Mobile, Inc.	Tempo Telecom			
Global Connection	TerraCom			
IM Telecom, LLC	Total Call Mobile			
Kajeet	True Wireless			
Linkup Telecom	Vast Communications			
LTS of Rocky Mount	You Talk Mobile			
Millennium 2000	ZING PCS			

Figure 4 Pending Wireless ETC Designation Petitions at FCC as of June 2016

Source: FCC Lifeline Compliance Plans & ETC Petitions

²³ FCC 15-71, WC Docket No. 11-42, Lifeline Reform and Modernization, Second Report and Order, released June 22, 2015, <u>https://apps.fcc.gov/edocs_public/attachmatch/FCC-15-71A1.pdf</u>, accessed on September, 28, 2016.

Figure 5 shows the six Florida ETCs with the largest number of Lifeline customers as of June 2016. These ETCs represent 99 percent of the total Lifeline customer participation.



Figure 5 Top Six Florida Lifeline ETCs as of June 2016

On May 2, 2016, Sprint announced the merger of its Assurance Wireless brand with Access Wireless' i-wireless brand.²⁴ Sprint will own 70 percent of the new business, with i-wireless owning the remaining 30 percent. The new combined company will continue to use the name i-wireless. In Florida, the combined company will have slightly more customers than SafeLink Wireless based on the 2016 data.

Figure 6 reflects USAC Lifeline disbursements to Florida ETCs between July 2015 and June 2016. The total amount disbursed during this 12 month period was \$91,499,102, an average of \$7,624,925 per month.

These dollars enabled Florida citizens qualifying for Lifeline benefits to receive discounted monthly bills with a current minimum credit of \$9.25, or a free Lifeline wireless phone with up to 250 free monthly minutes from certain wireless providers. These amounts also include support corrections or true-ups from prior months when errors are made.

Source: Industry responses to 2016 FPSC data requests

²⁴ Sprint Press Release, "Sprint Announces Wireless Lifeline Services Partnership with i-wireless, released May 2, 2016, <u>http://investors.sprint.com/news-and-events/press-releases/press-release-details/2016/Sprint-Announces-Wireless-Lifeline-Services-Partnership-with-i-wireless/default.aspx, accessed Oct. 28, 2016.</u>



Source: USAC Disbursements Florida July 2015-June 2016²⁵

²⁵ The fluctuation in Figure 6 for the month of September 2015 is the result of Assurance Wireless' filing dates for Lifeline credit reimbursement from the universal service fund. For March 2016, the fluctuation is a result of true-up reimbursements attributable to TracFone for 2015.

V. Lifeline Enrollment Process and Improvement Activities

A. Lifeline Electronic Coordinated Enrollment Process

Florida has in place a streamlined, efficient, and verifiable Lifeline Electronic Coordinated Enrollment process. This advanced process involves a computer interface between the FPSC and the DCF for Lifeline applicants who currently participate in the Medicaid, the SNAP, or the TCA program. The FCC and USAC have commended the Florida Lifeline Electronic Coordinated Enrollment process and said that it is a good example of an enrollment process that states should use for the Lifeline coordinated enrollment process.²⁶

B. Transitional Lifeline

In accordance with Section 364.105, Florida Statutes, current Lifeline customers who no longer meet eligibility criteria and are removed from Lifeline service are eligible to receive a 30 percent discount on the residential basic local service rate for a period of one year after ending Lifeline service. For example, a former Lifeline customer with a phone bill that includes a \$25.00 basic rate would receive a \$7.50 monthly discount for one year. Transitioning from Lifeline service means that the consumer's socio-economic status may have improved, and the customer may have advanced beyond the qualifying eligibility criteria.

Figure 7 presents the number of Transitional Lifeline customers for AT&T, Frontier (formally Verizon), and CenturyLink for June 2011 through June 2016. The large increase in the number of Transitional Lifeline participants in 2013²⁷ is attributable to customers being de-enrolled from the Florida Lifeline Program due to the new FCC requirement to annually recertify Lifeline customers. These former Lifeline participants may elect to receive Transitional Lifeline benefits for up to one year.



Source: Industry responses to FPSC data requests (2011-2016)

²⁶ FCC 15-71, WC Docket No. 11-42, Lifeline Reform and Modernization, Second Report and Order, released June 22, 2015, <u>https://apps.fcc.gov/edocs_public/attachmatch/FCC-15-71A1.pdf</u>, accessed September, 28, 2016, Footnote 215.

 ²⁷ In 2013, AT&T reported 32,783; CenturyLink reported 488; and Verizon reported 23. By comparison in 2016, AT&T reported 6,033; CenturyLink reported 747; and Frontier Florida reported 329.

C. Florida Public Service Commission Activities

Lifeline Work Group Meeting November 2016

The Lifeline Work Group was created by Section 364.10(2)(g)3., Florida Statutes, and includes the FPSC, DCF, OPC, and each Florida ETC offering Lifeline service. Its purpose is to determine how the eligible Lifeline subscriber information will be shared, the obligations of each party with respect to the use of that information, and the procedures to be implemented to increase enrollment and verify eligibility in these programs.

FPSC staff conducted a meeting of the Lifeline Work Group on November 3, 2016. The purpose of this meeting was for the Lifeline Work Group to discuss:

- The new FCC Order (FCC 16-38) and revised Lifeline rules
- FPSC rulemaking related to the Lifeline Program
- Readiness of Florida ETCs to implement the new rules by December 2, 2016
- Concerns with the new FCC rules
- Florida ETC Outreach plans to inform consumers of the new rules
- Standards to advertise the availability of Lifeline services using media of general distribution pursuant to federal rules.

Phone Club Corporation ETC Designation

The FPSC granted ETC designation to Phone Club Corporation (Phone Club) on September 23, 2016.²⁸ Phone Club was approved as an ETC for the limited purpose of receiving federal universal service low income support for providing Lifeline service to qualified households in non-rural AT&T Florida's service areas. Prior to its ETC designation, Phone Club had resold Lifeline Service from AT&T Florida.

As a result of the FCC's reforms in 2015, non-ETC resellers could no longer receive Lifeline discounts after August 15, 2016. As required by 2015 rules, Phone Club filed its proposed wireline Compliance Plan with the FCC to obtain forbearance from the facilities requirement of the Act, for the provision of Lifeline service, on July 26, 2016.²⁹ The FCC approved Phone Club's proposed Lifeline Compliance Plan on August 10, 2016.³⁰

Integrated Path ETC Designation

On January 11, 2016, Integrated Path filed an application for designation as an ETC with the FPSC.³¹ The application requested both low-income and high-cost ETC designation throughout AT&T Florida's service territory. The application also sought ETC designation in those AT&T Florida wire centers that serve federally recognized tribal lands.³² Integrated Path's application is pending consideration by the FPSC.

²⁸ FPSC Order No. PSC-16-0411-PAA-TX, Docket No. 160150-TX, issued Sept. 23 2016.

²⁹ Phone Club Compliance Plan, <u>https://www.fcc.gov/ecfs/filing/10725243429438/document/1072524342943875c5</u>.

³⁰ FCC Public Notice, WC Docket No. 09-197 and WC Docket No. 11-42, DA 16-905, Released August 10, 2016.

³¹ FPSC Docket No. 160016-TP.

³² The federal low income program includes Lifeline and link-up on federally recognized tribal lands, whereas in areas outside of federally recognized tribal lands, only Lifeline is available.

FPSC Continues Actions to Prevent Waste, Fraud and Abuse of the Federal Universal Service Fund

Florida continues to enforce safeguards to prevent waste, fraud, and abuse of the Universal Service Fund. Florida's participation with the National ETC State Coordinating Group to monitor prospective and existing ETCs across the country, has enabled information sharing with all states on a national basis.³³ Protecting against waste, fraud, and abuse in the Lifeline Program is contingent upon developing adequate safeguards to ensure that funds are being disbursed and expended according to state and federal regulations and guidelines.

The FPSC strives to protect the integrity of the Lifeline Program in the State of Florida and takes appropriate enforcement action when necessary. The FPSC has statutory authority to grant landline ETC designations, and can also revoke ETC status when warranted. Unlawful and inappropriate federal Universal Service Fund disbursements are inconsistent with public trust and negatively impacts states like Florida, which contribute more into the Universal Service Fund than it receives.

D. Federal Communications Commission Activities

2016 Lifeline Modernization Reform Order

On April 27, 2016, the FCC released its Lifeline Modernization Order. In this Order, the FCC took steps to both expand services supported and also limit the qualifying criteria consumers can use to sign up for Lifeline services. Some of the FCC new rules became effective in December 2016. Specific changes regarding qualifications can be found in Section III of this report. Consumers that are already enrolled in the Lifeline Program will continue to be eligible for up to one year from their initial application or recertification.

In addition to reforming eligibility, the FCC has also refocused the program goal on broadband adoption, encouraging adoption of minimum broadband standards ³⁴ by tying compliance with funding eligibility. Figure 8 below outlines the FCC's dates for new phased-in standards for mobile and fixed services.

Mobile and Fixed Service Standards						
Effective Dates	Mobile Voice	Mobile Broadband	Fixed Broadband			
From 12/2/16 to 11/30/17	500 Minutes	Usage Allowance: 500 MB	Speed 10/1 Usage Allowance: 150 GB			
From 12/1/17 to 11/30/18	750 Minutes	Usage Allowance: 1 GB	Undeted appually based			
From 12/1/18 to 11/30/19	1,000 Minutes	Usage Allowance: 2 GB	on usage reported to			
From 12/1/19 to 11/30/20	1,000 Minutes	Updated annually based on usage reported to FCC				

Figure 8 Mobile and Fixed Service Standards

Source: FCC 2016 Lifeline Reform Order (FCC 16-38)

³³ The ETC State Coordinating group includes state commission members from all fifty states, the District of Columbia, and the Commonwealth of Puerto Rico.

³⁴ Upon written notification to the FCC, certain ETCs do not have to comply with the broadband standards.

The FCC states that to be sustainable and achieve its goals of providing low-income consumers with robust, affordable and modern service offerings, a forward-looking Lifeline Program must focus on broadband services. Therefore, the FCC concludes that it is necessary that, following an extended transition period, to determine whether Lifeline will apply to a voice-only offering. The FCC did include an exception in those census blocks with only one Lifeline provider.

The Lifeline Program will continue to support voice services when bundled with a broadband service which meets the FCC's minimum service standards. Figure 9 outlines the FCC's phase down schedule.

Effective Dates	Fixed	Mobile	Fixed	Mobile	
Effective Dates	Voice	Voice	Broadband	Broadband	
Through 11/30/19	\$9.25	\$9.25	\$9.25	\$9.25	
From 12/1/19 to 11/30/20	\$7.25	\$7.25	\$9.25	\$9.25	
From 12/1/20 to 11/30/21	\$5.25	\$5.25	\$9.25	\$9.25	
After 11/30/21	$$0^{35}$	\$0	\$9.25	\$9.25	

Figure 9
Lifeline Support Phase Down Schedule

Source: FCC 2016 Lifeline Reform Order (FCC 16-38)

National Lifeline Eligibility Verifier

The FCC has established a national Lifeline eligibility verifier (national verifier) to make eligibility determinations and perform other functions related to the Lifeline Program. A national verifier would review consumer eligibility documentation to verify Lifeline eligibility, and where feasible, interface with state eligibility databases to verify Lifeline eligibility. The FCC's actions intend to achieve the following:

- A National Verifier would act as neutral third-party entity that removes the opportunity for providers to enroll ineligible subscribers
- Refines list of federal programs that may be used to validate Lifeline eligibility to those that support electronic validation, are most accountable, and best identify people needing support (SNAP, SSI, Medicaid, Veterans Pension, Tribal), along with income-based eligibility
- Increases transparency by making program data publicly available and understandable, including subscriber counts by provider and uniform disclosure of annual subscriber recertification data
- Determines subscriber eligibility
- Populates the Lifeline Eligibility Database
- Allows access to service providers, subscribers, states, and state administrators

Subscribers also would receive a call or text message during the 30-day period to prompt a response. Any subscriber response submitted after the 30-day deadline will not be processed, and the subscriber would be considered ineligible for the program and will be de-enrolled. If an ETC

³⁵ If determined that a voice-only service is no longer eligible for Lifeline support.

is unable to recertify a subscriber, the subscriber is offered transitional Lifeline benefits at a 30 percent discount of the local telecommunications service rate for one year.³⁶

2015 Recertification of Florida Lifeline Subscribers

The FCC adopted a set of uniform recertification procedures that all ETCs must perform annually to verify the ongoing eligibility of their Lifeline subscribers.³⁷ To comply with the annual requirement for 2015, all ETCs and state Lifeline administrators were required to recertify the eligibility of their Lifeline subscriber base by the end of 2015, and report the results to USAC by January 31, 2016. Subscribers failing to respond to recertification efforts had to be de-enrolled from Lifeline. As a result of the 2015 recertification process, 53,556 customers or 6 percent were de-enrolled from the Florida Lifeline Program.³⁸ Of the 53,556 customers deenrolled, 54 percent were as a result of Lifeline subscribers not responding to the recertification request. Results of the recertification by company are presented in Attachment C.

ETCs have the option of recertifying subscribers in one of three ways. The first is to verify program or income-based eligibility where an ETC can query the available database to confirm the subscriber's continued eligibility. The second means is, in the absence of a database, the ETC must recertify the continued eligibility of a subscriber by writing, phoning, text messaging, emailing, Interactive Voice Response, or otherwise through the Internet using an electronic signature.

The third method of recertifying Lifeline customers would be to have the ETC elect USAC to perform Lifeline recertification for their subscribers. USAC recertifies subscribers by mailing each subscriber a letter that provides the subscriber a notice, informing the subscriber that the subscriber has 30 days to recertify the subscriber's continued eligibility to receive Lifeline service or the subscriber will be de-enrolled from the Lifeline Program. The letter would also explain the recertification process and how the subscriber may confirm his or her eligibility. Subscribers also would receive a call or text message during the 30-day period to prompt a response. Any subscriber response submitted after the 30-day deadline will not be processed, and the subscriber would be considered ineligible for the program and will be de-enrolled. If an ETC is unable to recertify a subscriber, the subscriber is offered transitional Lifeline benefits at a 30 percent discount of the local telecommunications service rate for one year.³⁹

Duplicate Lifeline Support

Eligible consumers can only receive one Lifeline-supported service per household.⁴⁰ If there are two households residing at one address and each desires to participate in Lifeline, each applicant has to complete a one-per-household worksheet to demonstrate that each applicant is living in a separate economic unit and not sharing living expenses (bills, food, etc.) or income with another resident.41

³⁶ Section 364.105, Florida Statutes, Discounted rate for basic service for former Lifeline subscribers. ³⁷ 47 C.F.R. § 54.410(f).

³⁸ By comparison, the 2014 recertification processes de-enrolled 142,248 customers or 14 percent of participants from the Florida Lifeline program.

³⁹ Section 364.105, Florida Statutes. Discounted rate for basic service for former Lifeline subscribers.

⁴⁰ 47 C.F.R. § 54.409(c).

⁴¹ A household Lifeline eligibility pre-screening tool is available at www.lifelinesupport.org.

The FCC directed USAC to establish a database to both eliminate existing duplicative support and prevent duplicative support in the future.⁴² To prevent waste in the Universal Service Fund, the FCC created and mandated the use by ETCs of a National Lifeline Accountability Database (NLAD) to ensure that multiple ETCs do not seek and receive reimbursement for the same Lifeline subscriber. NLAD conducts a nationwide real-time check to determine if the consumer or another person at the address of the consumer is already receiving a Lifeline Programsupported service. Florida ETCs were operational on NLAD starting March 6, 2014. At Florida's request, the FCC has agreed to allow states to have read-only access to this database starting in September 2015, to help prevent waste, fraud, and abuse of the Lifeline Program.

⁴² FCC 12-11, WC Docket No. 11-42, Lifeline Reform and Modernization, Report and Order, released Feb. 6, 2012, <u>https://apps.fcc.gov/edocs_public/attachmatch/FCC-12-11A1.pdf</u>, accessed Oct. 27, 2016.

VI. Lifeline Promotion Activities

Promotional activities by the FPSC in 2016 featured participation in National Consumer Protection Week, Older Americans Month, and ongoing "grassroots" efforts to increase awareness and enrollment in the Lifeline Program. Figure 10 represents the various events and locations where Lifeline information was shared in Florida as of August 2016.

Lifeline Across America

The Lifeline Across America Working Group includes representatives from the Federal Communications Commission, National Association of Regulatory Utility Commissioners (NARUC), and National Association of State Utility Consumer Advocates. The working group's primary national effort is to ensure that low income families and individuals are aware of the Lifeline Program and understand the participation requirements, including annual recertification and only one Lifeline discount per household. Supported by the working group, Lifeline Awareness Week promotes these messaging efforts. In April 2016, the FCC released its Lifeline Modernization order, and the working group agreed no further conference calls and/or promotional planning were necessary until the new federal Lifeline guidelines were implemented.

National Lifeline Awareness Week

In August 2016, NARUC announced that Lifeline Awareness Week, normally recognized each September, would be postponed due to the new federal guidelines. NARUC reported it will take time for carriers and states, especially those with matching programs, to adjust to the FCC's Lifeline Program changes. To avoid consumer confusion by providing outdated information, NARUC postponed the 2016 awareness week.

National Consumer Protection Week and Other Community Events

The FPSC seeks existing community events as well as new venues and opportunities where Lifeline educational materials can be distributed and discussed with citizens. National Consumer Protection Week (NCPW), March 6-12, 2016, was such an opportunity for Lifeline outreach activities. An annual consumer education campaign, NCPW encourages consumers to take advantage of their consumer rights. For this year's event, FPSC Chairman Julie I. Brown kicked off the week by hosting a press conference in Tallahassee at America's Second Harvest of the Big Bend to help consumers get access to food and phone service. Event participants included Commissioner Nancy Miller, City of Tallahassee; Katrina Rolle, President/CEO, United Way of the Big Bend; and Jim Croteau, Interim CEO of America's Second Harvest of the Big Bend. The participants shared information for low-income residents to maintain a healthy lifestyle, through access to good nutrition and to phone service to connect with job opportunities, emergency services, family, and friends. Also during the week, FPSC staff made presentations in Jacksonville, Tampa, St. Petersburg, and Panama City, showing consumers how to apply for Lifeline, if they qualify.

For the fifth year, the FPSC participated in the national Older Americans Month project; celebrated each May to honor and recognize older Americans for their contributions to families, communities, and society. *Blaze A Trail* was this year's theme, and the FPSC hosted and

attended 11 educational sessions, distributing Lifeline, conservation, and fraud prevention information at senior communities in Bay, Broward, Duval, Hillsborough, and Leon Counties.

Each month, the FPSC also names a valued partner agency or organization as a "Helping Hand," for helping raise public awareness about the Lifeline Program, energy and water conservation, and utility impersonation scams. One ongoing FPSC partner is the Jacksonville Senior Expo, where more than 7,000 seniors attend and have access to Commission brochures and publications, as well as to FPSC staff.

Lifeline Events and Locations			
Active Living Expo	Evergreen Missionary Baptist Church		
Senior Day at the Capitol	Trinity Café		
Woodland Point Apartments	St. Petersburg Free Clinic		
Hollyridge Apartments	Healthy Wealthy Senior Living Fair		
River House Senior Center	Senior Awareness Day, Pensacola		
Coastal Community Center	Lunch and Learn - Lake Jacksonville Senior Center		
Trout Creek Senior Center	Lunch & Learn Bradfordville Senior Center		
Leon County Senior Outreach Appreciation	Fraud Prevention Seminar		
Mtg.			
Community Day of Empowerment – Live Oak	World Elder Abuse Awareness Day – Tallahassee		
Community Day of Empowerment – Gainesville	World Elder Abuse Awareness Day – Melbourne		
Community Day of Empowerment – Newberry	Career Source Capital Region Job and Resource Fair		
Community Day of Empowerment – High	Newberry Municipal Senior Building		
Springs			
Micanopy Town Hall Community Meeting	High Springs Civic Center		
Thelma Boltin Center	FOOD4KIDZ		
High Springs Senior Center	Springfield Center		
Apopka Job Connection Center	Daniel D. Cantor Senior Center		
Kissimmee Job Connection Center	Sunrise Senior Center		
Waldo Community Center	Southcentral/Southeast Focal Point Senior Center		
LifeStyle Enrichment Center of Ft. White	Woodville Community Center		
33 rd Annual Children's Day – Florida Museum	Feeding Northeast Florida		
of History			
LifeStyle Enrichment Center of Lake City	The Oaks at Riverview Senior Center		
Columbia County Public Library	Bennie Furlong Senior Center		
Feeding Northeast Florida Christian Fellowship	7 th Annual Southside Community Health & Fitness		
Ministries	Fair-Maranatha Seventh Day Adventist Church		
Suwanee County Health and Wellness Fair at	Jacksonville Senior Expo		
Advent Christian Village in Dowling Park			
Panama City Beach Senior Center	Bay County Area Council on Aging		

Figure 10 Commission Lifeline Promotion in Florida

Source: Florida Public Service Commission, Office of Consumer Assistance & Outreach

Library Outreach Campaign

Each year, the FPSC provides educational packets, including FPSC publications and Lifeline brochures and applications in English, Spanish, and Creole, to Florida public libraries across the state for consumer distribution. The FPSC's Library Outreach Campaign reached 583 state

public libraries and branches in 2016. To reduce mailing and production costs, the Commission sent the materials via a CD that included print-ready brochure copies for easy reproduction. Following the Campaign, many libraries' requests for additional publications are filled.

Community Services Block Grant Program

The Florida Department of Economic Opportunity includes Lifeline services as an indicator in its work plan, allowing Community Action Agencies to report the number of clients they help to secure Lifeline services. During the October 1, 2014 – September 30, 2015 reporting period, 1,645 households applied for Lifeline benefits through local Community Action Agencies, providing \$215,166 in benefits to clients. For the reporting period, 14 of the 27 Community Action Agencies provided Lifeline enrollment services to clients.

Income-Based Lifeline Applicants

OPC provides assistance to consumers applying for Lifeline Assistance based upon income level. During the July 2015 - June 2016 reporting period, OPC received over 5,000 calls from potential applicants seeking assistance and processed 11,689 applications. OPC verifies consumers' income eligibility for the following telecommunication carriers: Assurance Wireless, AT&T Landline, CenturyLink Landline, Frontier Landline (formally Verizon), SafeLink Wireless, and T-Mobile Wireless.

Lifeline Partners

Agencies and organizations that regularly interact with eligible consumers must have easy access to Lifeline information to support program awareness efforts. The FPSC partners with many agencies year-round to make sure eligible consumers know about Lifeline and know how to apply. The Lifeline Partners listed in the next section have continued to help develop Lifeline awareness by participating in local community events, offering training sessions, providing updates about program changes, and supplying brochures and applications.

Ongoing Lifeline Outreach

The local, state, and federal agencies, organizations, businesses, and telecommunications companies listed in Attachment D are involved in the collaborative effort to increase awareness and participation in the Lifeline Program. Each month, the FPSC sends a cover letter and informational packet to two organizations to encourage continued Lifeline outreach to their eligible clientele. Additionally, the FPSC schedules and conducts two monthly community events to promote Lifeline.

VII. Conclusion

As of June 30, 2016, 852,255 eligible customers participated in the Florida Lifeline Program. The success of the Florida Lifeline Program can be attributed to the continued partnership between the FPSC, DCF, OPC, and other agencies around the state that assist Florida low-income families.

As a result of Florida Lifeline participation, USAC Low Income disbursements for Florida ETCs for the 12-month period ending June 2016 totaled approximately \$92 million. These dollars enabled Florida citizens qualifying for Lifeline benefits to receive discounted monthly bills with a current credit of at least \$9.25, or a free Lifeline wireless phone with 250 free monthly minutes. The ETC designation of successful wireless providers, such as SafeLink Wireless Assurance Wireless, and i-wireless, which provide a free phone and free monthly minutes to the customer, has been a major growth factor in the Florida Lifeline Program the last several years.

Efforts to increase Lifeline participation can be separated into two categories, consumer outreach and enrollment process. The FPSC, in cooperation with other state and federal agencies, the OPC, ETCs, and other organizations, remains engaged in extensive outreach efforts. Because most of these efforts run concurrently, measuring the impact of any single activity on Lifeline participation is difficult. Nevertheless, outreach efforts overall are having a positive outcome and should be continued. Outreach efforts are also being expanded to include more competitive local exchange carrier and wireless ETCs.

The FPSC continues to focus on enrollment process issues as a means of increasing participation. As previously discussed in this report, specific enrollment process initiatives include the following:

- FPSC Lifeline Coordinated Online Application Process
- FPSC/DCF Coordinated Lifeline Enrollment
- Annual Recertification Procedures
- DCF Certification/Verification Web Services Interface
- Lifeline Work Group Meetings
- National Lifeline Accountability Database

The FPSC remains committed to enabling low-income households in Florida obtain and maintain basic local telephone service to help them find jobs, contact community services, call doctors and schools, and connect to family and friends. The FPSC will continue to identify and find solutions to barriers that may prevent Lifeline from achieving greater success for the benefit of Florida's low-income consumers. The FPSC will also continue its work on streamlining the Lifeline enrollment process and refining the FPSC/DCF Lifeline coordinated application procedure in Florida so that applying for the Lifeline Program is easier and faster than in previous years while implementing the new FCC requirements.

Persons in family / household	2016 U.S. Federal Poverty Guidelines	150% of Federal Poverty Guidelines	Monthly income at 150% of Federal Poverty Guidelines	135% of Federal Poverty Guidelines	Monthly income at 135% of Federal Poverty Guidelines
1	\$11,880	\$17,820	\$1,485	\$16,038	\$1,337
2	\$16,020	\$24,030	\$2,003	\$21,627	\$1,802
3	\$20,160	\$30,240	\$2,520	\$27,216	\$2,268
4	\$24,300	\$36,450	\$3,038	\$32,805	\$2,734
5	\$28,440	\$42,660	\$3,555	\$38,394	\$3,200
6	\$32,580	\$48,870	\$4,073	\$43,983	\$3,665
7	\$36,730	\$55,095	\$4,591	\$49,586	\$4,132
8	\$40,890	\$61,335	\$5,111	\$55,202	\$4,600

Attachment A 2016 U.S. Poverty Guidelines

For families/households with more than 8 persons, add \$4,160 for each additional person.

Source: Department of Health and Human Services, Annual Update of the Department of Health and Human Service Poverty Guidelines. Federal Register Notice, January 15, 2016.

https://www.federalregister.gov/documents/2016/01/25/2016-01450/annual-update-of-the-hhs-poverty-guidelines .
	ETCs	June 2013	June 2014	Net Growth Rate	June 2015	Net Growth Rate	June 2016	Net Growth Rate
	SafeLink	490,828	543,174	11%	470,695	-13%	406,506	-14%
Wireless	Assurance	323,014	249,664	-23%	208,902	-16%	232,481	11%
	i-wireless/ Access	12,450	97,044	679%	106,440	10%	179,429	69%
	T-Mobile	1,373	3,091	125%	2,110	-32%	762	-64%
	CenturyLink	22,179	18,756	-15%	16,163	-14%	12,528	-22%
	AT&T	44,796	28,156	-37%	18,302	-35%	11,404	-38%
ne	Frontier Florida	11,327	8,245	-27%	4,721	-43%	3,896	-17%
reliı	Windstream	5,176	4,348	-16%	2,746	-37%	2,436	-11%
Wi	FairPoint	1,437	1,307	-9%	671	-49%	526	-22%
ent	NEFCOM	712	545	-23%	458	-16%	286	-38%
cumb	TDS Telecom	582	406	-30%	264	-35%	179	-32%
In	ITS Telecom	112	77	-31%	80	4%	86	8%
	Frontier of the South	114	84	-26%	46	-45%	28	-39%
	Smart City	21	12	-43%	7	-42%	11	57%
	Cox Telecom	41	522	100%	659	26%	689	5%
ine	TeleCircuit	637	666	5%	337	-49%	646	92%
Wirel	Knology d/b/a WOW	516	294	-43%	138	-53%	79	-43%
mpetitive ^v	Global Connection ⁴³	11	16	45%	8	-50%	3	-63%
	Non-ETC Reseller	979	658	-33%	495	-25%	71	-86%
Cc	ETCs which Relinquished Designation	1,162	468	-60%	184	-61%	0	-100%
	Total	917,467	957,533	4%	833,426	-13%	852,046	2%

Attachment B Lifeline Net Enrollment and Year-to-Year Net Growth Rate

Sources: FPSC data requests (2013-2016).

 $[\]overline{}^{43}$ Historical data has been corrected to remove resold lines that were counted twice.

	ETCs	Lifeline Subscribers	No Subscriber Recertification Response	Subscribers Reported - No Longer Eligible	Finding of Ineligibility	Lifeline Subscribers De-Enrolled	Percent of Lifeline Subscribers De-Enrolled
Wireless	SafeLink	480,672	1,968	0	21,105	23,073	5%
	Assurance	200,616	8,812	2,204	0	11,016	5%
	i-wireless/ Access	118,710	8,418	31	0	8,449	7%
	T-Mobile	2,110	890	0	0	890	42%
	CenturyLink	16,700	3,575	0	0	3,575	21%
	AT&T	13,635	4,664	9	0	4,673	34%
ne	Frontier Florida	4,260	0	0	752	0	18%
reli	Windstream	2,360	0	0	965	965	41%
Wi	FairPoint	877	254	4	0	258	29%
ent	NEFCOM	423	177	2	0	179	42%
cumb	TDS Telecom	270	97	0	0	97	36%
In	ITS Telecom	72	16	0	0	16	22%
	Frontier of the South	50	0	0	5	5	10%
	Smart City	6	0	0	0	0	0%
line	Cox Telecom	602	0	0	246	246	41%
/ire	TeleCircuit	0	0	0	0	0	0%
ive W	Knology d/b/a WOW	169	0	0	41	41	24%
npetiti	Global Connection	3	0	0	0	0	0%
Cor	Budget Prepaid	186	73	0	0	73	39%
	Total	841,721	28,944	2,250	23,114	53,556	6%

Attachment C Lifeline Subscriber Recertification as of February 2015

Source: Form 555 submitted to FCC and Universal Service Administrative Company by ETCs, Due by January 31, 2016.

Florida	
FIORICA	Lifeline Partners
AARP - Florida Chapter	Ability Housing of Northeast Florida
ACCESS Florida Community Network Partners	Agency for Health Care Administration (AHCA)
Agency for Persons with Disabilities	Aging Matters in Brevard County
Aging With Dignity	Florida Senior Medicare Patrol
Alliance for Aging, Inc.	Florida Senior Program
America's Second Harvest of the Big Bend, Inc.	Florida Telecommunications Relay, Inc. (FTRI)
Area Agencies on Aging	Florida Voters League
Big Bend 2-1-1 and other 2-1-1 Agencies	1000 Friends of Florida, Inc.
Boley Centers, Inc.	Habitat for Humanity – Florida
Braille and Talking Book Library	HANDS of Central Florida
Brain Injury Association of Florida, Inc.	Hemophilia Foundation of Greater Florida
Broward County Elderly and Veterans Services Division	Hispanic Office for Local Assistance
Bureau of Indian Affairs Programs	HOPE Connection
Capital Area Community Action Agency, Inc. (CACAA)	Leon County School Board
Catholic Charities of Central Florida	Little Havana Activities and Nutrition Centers of Dade County, Inc.
Centers for Drug Free Living	Living Stones Native Circle
Centers for Independent Living	Marion Senior Services
Central Florida Community Action Agency	Mid-Florida Housing Partnership, Inc.
City and County Consumer Assistance Departments	Miccosukee Tribe of Indians of Florida
City and County Housing Authorities	Monroe County Social Services
Communities In Schools Foster Grandparent Program	Feeding South Florida
Community Partnership Group	NAACP (Florida Associations)
Disability Rights Florida	One-Stop Career Centers (DEO)
Faith Radio Station and other Florida radio stations	Seminole County Government Community Development
Federal Social Security Administration (SSA) - Tallahassee District	Seniors First
First Quality Home Care	Senior Resource Alliance
Florida Alliance for Information and Referral Services (FLAIRS)	South East American Council, Inc.

Attachment D Agencies, Organizations, and Business Lifeline Partners

Florida Lifeline Partners (continued)							
Florida Assisted Living Association	Refuge House of the Big Bend						
Florida Association for Community	Tallahassee Memorial Hospital (TMH) and other						
action (FACA)	Florida hospitals						
Florida Association of Community	Tallahassee Urban League						
Florida Association of Counties	Tampa Vet Center						
Florida Association of County Human	Three Rivers Legal Services Inc						
Service Administrators	The Rivers Legar Services, Inc.						
Florida Association of Food Banks	United Home Care Services						
(FAFB)							
Florida Association of Housing and	United Way of Florida						
Florida Coalition for Children	Urban Leagues of Florida						
Florida Coalition for the Homelass	U.S. Department of Housing and Urban						
Pionua Coantion for the Homeless	Development (HUD)						
Florida Council on Aging	Washington County Council on Aging						
Florida Deaf Services Centers	Wakulla County Senior Citizens Council						
Association							
Florida Department of Children and	Nursing Homes Administrators						
Families (DCF)	Elorida Dopartment of Education						
Affairs (DCA)	Tionda Department of Education						
Florida Department of Economic	Florida Department of Revenue (DOR)						
Opportunity (DEO)							
Florida Department of Elder Affairs	Florida Developmental Disabilities Council						
(DEA) Florida Department of Veterans' Affairs	Florida Home Partnershin						
(DVA)	Tionda Home Farthership						
Florida Elder Care Services	Florida Housing Coalition						
Florida Hospital Association	Florida League of Cities, Inc.						
Florida Housing Finance Corporation	Florida Nurses Association						
Florida Low Income Housing Associates	Florida Public Libraries						
Florida Office of Public Counsel (OPC)	Florida Rural Legal Services, Inc.						
Florida Public School Districts	HOPE Community Center						
ASPIRE Health Partners	National Church Residences						
Goodwill Industries of Central Florida	Good News Outreach						
Florida Department of Education	Aging True Community Senior Services						
Elder Options							

Attachment 4



Public Service Commission

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

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

DATE: November 15, 2016
TO: Braulio L. Baez, Executive Director
FROM: Moniaishi Mtenga, Engineering Specialist I, Division of Engineering
RE: Review of 2016 Ten-Year Site Plan
CRITICAL INFORMATION: Place on November 29, 2016 Internal Affairs Agenda. Approval by the Commission is required by December 31, 2016.

Pursuant to Section 186.801(2), F.S., the Commission is required to classify each generating electric utility's Ten-Year Site Plan as either "suitable" or "unsuitable" by December 31 each year. The attached draft satisfies this requirement and its approval by the Commission is sought.

Please let me or Phillip Ellis know if you have any questions or need additional information in reference to the attached document.

Thank you.

MCM:tj

Attachment

cc: Division of Engineering (P. Ellis, L. King, T. Ballinger) Deputy Executive Director – TECH (M. Futrell)

REVIEW OF THE

2016 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES



NOVEMBER 2016

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List of Ten-Year Site Plan Utilities

Name	Abbreviation						
Investor-Owned Electric Utilities							
Florida Power & Light Company	FPL						
Duke Energy Florida, LLC.	DEF						
Tampa Electric Company	TECO						
Gulf Power Company	GPC						
Municipal Elec	ctric Utilities						
Florida Municipal Power Agency	FMPA						
Gainesville Regional Utilities	GRU						
JEA	JEA						
Lakeland Electric	LAK						
Orlando Utilities Commission	OUC						
City of Tallahassee Utilities	TAL						
Rural Electric	Rural Electric Cooperatives						
Seminole Electric Cooperative	SEC						

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Executive Summary

Integrated resource planning (IRP) is a utility process that includes a cost-effective combination of demand-side resources and supply-side resources. While each utility has slightly different approaches to IRP, some things are consistent across the industry. Each utility must update its load forecast assumptions based on Florida Public Service Commission (Commission) decisions in various dockets, such as demand-side management goals. Changes in government mandates, such as appliance efficiency standards, building codes and environmental requirements, must also be considered. Other input assumptions such as demographics, financial parameters, generating unit operating characteristics, fuel costs, etc. are more fluid and do not require prior approval by the Commission. Each utility then conducts a reliability analysis to determine when resources may be needed to meet expected load. Next, an initial screening of demand-side and supply-side resources is performed to find candidates that meet the expected resource need. The demand-side and supply-side resources are combined in various scenarios to decide which combination meets the need most cost-effectively. After the completion of all these components, utility management reviews the results of the varying analyses and the utility's Ten-Year Site Plan is produced as the culmination of the IRP process. Commission Rules also require the utilities to provide aggregate data which provides an overview of the State of Florida electric grid.

The Commission's annual review of utility Ten-Year Site Plans is non-binding but it does provide state, regional, and local agencies advance notice of proposed power plants and transmission facilities. Any concerns identified during the review of the utilities' Ten-Year Site Plans may be addressed by the Commission at a formal public hearing, such as a power plant need determination proceeding. While Florida Statutes and Commission Rules do not specifically define IRP, they do provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

Pursuant to Section 186.801, Florida Statutes (F.S.), each generating electric utility must submit to the Commission a Ten-Year Site Plan which estimates the utility's power generating needs and the general locations of its proposed power plant sites over a 10-year planning horizon. The Ten-Year Site Plans of Florida's electric utilities summarize the results of each utility's IRP process and identifies proposed power plants and transmission facilities. The Commission is required to perform a preliminary study of each plan and classify each one as either "suitable" or "unsuitable." This document represents the review of the 2016 Ten-Year Site Plans for Florida's electric utilities.

All findings of the Commission are made available to the Florida Department of Environmental Protection (DEP) for its consideration at any subsequent certification proceeding pursuant to the

¹Investor-owned utilities filing 2016 TYSPs include Florida Power & Light Company (FPL), Duke Energy Florida, LLC. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). Municipal utilities filing 2016 TYSPs include Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). Seminole Electric Cooperative (SEC) also filed a 2016 TYSP.

Electrical Power Plant Siting Act or the Electric Transmission Line Siting Act.² In addition, this document is sent to the Florida Department of Agriculture and Consumer Services pursuant to Section 377.703(2)(e), F.S., which requires the Commission provide a report on electricity and natural gas forecasts.

Review of the 2016 Ten-Year Site Plans

The Commission has divided this review into two portions: a Statewide Perspective, which covers the whole of Florida, and Utility Perspectives, which address each of the reporting utilities. From a statewide perspective, the Commission has reviewed the implications of the combined trends of Florida's electric utilities regarding load forecasting, renewable generation, and traditional generation.

Load Forecasting

Forecasting load growth is an important component of system planning for Florida's electric utilities. Florida's electric utilities reduce the rate of growth in customer peak demand and annual energy consumption through demand-side management programs. The Commission, through its authority granted by Sections 366.80 through 366.83 and Section 403.519, F.S., otherwise known as the Florida Energy Efficiency and Conservation Act (FEECA), encourages demand-side management by establishing goals for the reduction of seasonal peak demand and annual energy consumption for those utilities under its jurisdiction. Based on current projections, Florida's electric utilities anticipate exceeding the historic 2007 peak by 2019. Figure 1 below details these trends.



²The Electrical Power Plant Siting Act is Sections 403.501 through 403.518, F.S. Pursuant to Section 403.519, F.S., the Commission is the exclusive forum for the determination of need for an electrical power plant. The ElectricTransmission Line Siting Act is Sections 403.52 through 403.5365, F.S. Pursuant to Section 403.537, F.S., the Commission is the sole forum for the determination of need for a transmission line.

Renewable Generation

Renewable resources continue to expand in Florida, with approximately 1,860 MW of renewable generating capacity currently installed in Florida. The majority of installed renewable capacity is represented by biomass and municipal solid waste, making up approximately 60 percent of Florida's renewables. Other major renewable types, in order of capacity contribution, include waste heat, solar, hydroelectric, and landfill gas. Notably, Florida had 108 MW of demand-side renewable energy systems installed and using net metering at the end of 2015, an increase in capacity of 34.7 percent from 2014.

Over the next 10 years, Florida's electric utilities have reported that 2,016 MW of additional renewable generation is planned in Florida, excluding any potential demand-side renewable energy additions. Over three-quarters of the projected capacity additions are solar photovoltaic generation. Some utilities are including a portion of these solar resources (124 MW) as a firm resource for reliability considerations. Reasons given for these additions are a continued reduction in the price of solar facilities, availability of utility property with access to the grid, and actual performance data obtained solar demonstration projects. If these conditions continue, cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels.

Traditional Generation

Generating capacity within the State of Florida is anticipated to grow to meet the increase in customer demand, with approximately 12,318 MW of new utility-owned generation added over the planning horizon. This figure represents an increase from the previous year, which estimated the need for about 11,548 MW new generation. Natural gas remains the dominant fuel over the planning horizon, with usage in 2015 at approximately 63 percent of the state's net energy for load (NEL). Figure 2 below illustrates the use of natural gas as a generating fuel for electricity production in Florida. Natural gas usage is expected to grow slowly.



Based on the 2016 Ten-Year Site Plans, Figure 3 below illustrates the present and future aggregate capacity mix of the State of Florida. The capacity values in Figure 3 incorporate all proposed additions, changes, and retirements planned during the 10-year period. As in previous planning cycles, natural gas-fired generating units make up a majority of the generation additions and now represent a majority of capacity within the state.



Source: 2016 FRCC Load and Resource Plan and TYSP Data Responses

As noted previously, the primary purpose of this review of the utilities' plans is to provide information regarding proposed electric power plants for local and state agencies to assist in the certification process. Table 1 below displays those planned generation facilities that have not yet received a determination of need from the Commission. A petition for a determination of need is generally anticipated four years in advance of the in-service date for a natural gas-fired combined cycle unit.

Table 1: State of Florida - Planned Units Requiring a Determination of Need								
	Year	Utility Name	Unit Name	Fuel & Unit Type	Net Capacity (Sum MW)			
	2021	SEC	Unnamed CC	Natural Gas Combined Cycle	649			
	2023	OUC	Unspecified CC	Natural Gas Combined Cycle	300			
	2024	FPL	Combined Cycle Unit	Natural Gas Combined Cycle	1,317			
Source: 2	016 Ten	-Year Si	te Plans					

Future Concerns

Florida's electric utilities must also consider environmental concerns associated with existing generators and planned generation to meet Florida's electric needs. The U.S. Environmental Protection Agency (EPA) has finalized several new rules that are expected to have a sizeable impact on Florida's existing generation fleet, as well as on its proposed new facilities.

Notably, EPA published final rules in October 2015 associated with carbon pollution for existing power plants, also known as the Clean Power Plan. On the same date, EPA also published final rules setting carbon emissions from new facilities. These rules have been appealed. The U.S. Supreme Court has stayed the Clean Power Plan during the appeal process. Consequently, the potential effects on Florida's electric utilities are not considered as part of this review.

Conclusion

The Commission has reviewed the 2016 Ten-Year Site Plans and finds that the projections of load growth appear reasonable. The reporting utilities have identified sufficient additional generation facilities to maintain an adequate supply of electricity at a reasonable cost. The Commission will continue to monitor the impact of current and proposed EPA Rules and the state's dependence on natural gas for electricity production.

Based on its review, the Commission finds the 2016 Ten-Year Site Plans to be suitable for planning purposes. Since the Plans are not a binding plan of action for electric utilities, the Commission's classification of these Plans as suitable or unsuitable does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

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Introduction

The Ten-Year Site Plans (TYSPs or Plans) of Florida's electric utilities are the culmination of an integrated resource plan which is designed to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. The Commission receives comments from these agencies regarding any issues with which they may have concerns. The Plans are planning documents that contain tentative data that is subject to change by the utilities upon written notification to the Commission.

For any new proposed power plants and transmission facilities, certification proceedings under the Florida Electrical Power Plant Siting Act, Sections 403.501 through 403.518, Florida Statutes (F.S.), or the Florida Electric Transmission Line Siting Act, Sections 403.52 through 403.5365, F.S., will include more detailed information than is provided in the Plans. The Commission is the exclusive forum for determination of need for electrical power plants, pursuant to Section 403.519, F.S., and for transmission lines, pursuant to Section 403.537, F.S. The Plans are not intended to be comprehensive, and therefore may not have sufficient information to allow regional planning councils, water management districts, and other reviewing state and local agencies to evaluate site-specific issues within their respective jurisdictions. Other regulatory processes may require the electric utilities to provide additional information as needed.

Statutory Authority

All major generating electric utilities are required by Section 186.801, F.S., to submit at least every two years, for review, a Ten-Year Site Plan to the Commission. Based on these filings, the Commission performs a preliminary study of each Plan and makes a non-binding determination as to whether it is suitable or unsuitable. The results of the Commission's study are contained in this report, the Review of the 2016 Ten-Year Site Plans, and are forwarded to the Florida Department of Environmental Protection for use in subsequent proceedings. In addition, Section 377.703(2)(e), F.S., requires the Commission to collect and analyze energy forecasts, specifically for electricity and natural gas, along with the Department of Agriculture and Consumer Services. The Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code (F.A.C.) in order to fulfill these statutory requirements and provide a solid framework for flexible, cost-effective utility resource planning. In this way, the Commission fulfills its oversight and regulatory responsibilities while leaving day-to-day planning and operations to utility management.

Applicable Utilities

Florida is served by 58 electric utilities, including 5 investor-owned utilities, 35 municipal utilities, and 18 rural electric cooperatives. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity of 75 MW or greater are required to file with the Commission a Ten-Year Site Plan every year.

In 2016, 11 utilities met these requirements and filed a Ten-Year Site Plan, including 4 investorowned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, LLC (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2016 Plan is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

Figure 4 below illustrates the comparative size of the TYSP utilities, in terms of each utility's percentage share of the state's retail energy sales in 2015. Combined, the reporting investor-owned utilities account for 78.6 percent of the state's retail energy sales. The reporting municipal and cooperative utilities make up approximately 19.8 percent of the State's retail energy sales.



Required Content

The Commission requires each reporting utility to provide information on a variety of topics. Schedules describe the utility's existing generation fleet, customer composition, demand and energy forecasts, fuel requirements, reserve margins, changes to existing capacity, and proposed power plants and transmission lines. The utilities also provide a narrative documenting the methodologies used to forecast customer demand and the identification of resources to meet that demand over the 10-year planning period. This information, supplemented by additional data requests, provides the basis of the Commission's review.

Additional Resources

The Commission's Rules also task the reporting electric utilities with collecting information on both a statewide basis and for Peninsular Florida, which excludes the area west of the Apalachicola River. The Florida Reliability Coordinating Council (FRCC) provides this aggregate data for the Commission's review. Each year, the FRCC publishes a Regional Load and Resource Plan, which contains historic and forecast data on demand and energy, capacity and reserves, and proposed new generating units and transmission line additions. In addition, the FRCC publishes an annual Reliability Report which is also relied upon by the Commission.

For certain comparisons additional data from various government agencies is relied upon, including the Energy Information Administration and the Florida Department of Highway Safety and Motor Vehicles.

The Commission held a public workshop on September 14, 2016, to facilitate discussion of the annual planning process and allow for public comments. A presentation was conducted by the FRCC summarizing the 2016 Load and Resource Plan and other related matters, including fuel reliability, environmental regulations, and physical security of infrastructure. Presentations were also conducted by the four IOU's FPL, DEF, TECO and GPC to discuss their planning process. Comments from Southern Alliance for Clean Energy and Sierra Club were also given at the workshop.

Structure of the Commission's Review

The Commission's review is divided into multiple sections. The Statewide Perspective provides an overview of the State of Florida as a whole, including discussions of load forecasting, renewable generation, and traditional generation. The Utility Perspectives provides more focus, discussing the various issues facing each electric utility and its unique situation. Lastly, the comments collected from various review agencies, local governments, and other organizations are included as Appendix A.

Conclusion

Based on its review, the Commission finds all 11 reporting utility's 2016 Ten-Year Site Plans to be suitable for planning purposes. During its review, the Commission has determined that the projections for load growth appear reasonable and that the reporting utilities have identified sufficient generation facilities to maintain an adequate supply of electricity at a reasonable cost.

The Commission notes that, as the Ten-Year Site Plans are non-binding, the classification of suitable does not constitute a finding or determination in any docketed matter before the Commission, nor an approval of all planning assumptions contained within the Ten-Year Site Plans. The Commission may address any concerns raised by a utility's Ten-Year Site Plan at a public hearing.

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Statewide Perspective

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Load Forecasting

Forecasting load growth is an important component of the IRP process for Florida's electric utilities. In order to maintain system reliability, utilities must be prepared for future changes in electricity consumption, including changes to the number of electric customers, customer usage patterns, building codes and appliance efficiency standards, new technologies such as electric vehicles, and the role of demand-side management.

Electric Customer Composition

Residential customers represent the majority in terms of number of customers at 88.7 percent of customers, and retail energy sales for the three major customer classes, as illustrated in Figure 5 below. Both commercial and industrial customers make up a sizeable percentage of energy sales, due to each class' higher energy usage per customer account.



Florida's residential customers make up a larger portion of retail energy sales than the United States as a whole, with a national average of 38 percent for residential retail sales. As a result, Florida's utilities are impacted more by trends in residential energy usage, which tend to be associated with weather conditions. Florida's residential customers rely more upon electricity for heating than the national average, with only a small portion using alternate fuels such as natural gas or oil for home heating needs.

Florida's unique climate plays an important role in electric utility planning. Florida is an outlier in terms of climate, with the highest number of cooling degree days and lowest number of heating degree days within the continental United States, as shown below in Figure 6. Other states tend to rely upon alternative fuels for heating, but Florida's heavy use of electricity results in high winter peak demand.



Source: National Oceanic & Atmospheric Administration, Historical Climatology Series 5-1 and 5-2

Growth Projections

For the next 10-year period, Florida's customer base and retail sales are anticipated by the reporting utilities to grow at a faster pace than the last few years, reversing a trend of small population increases with declining retail sales. While this rate remains below those experienced before the financial crisis, it would set the State on track to exceed its previous 2007 retail sales peak in 2019. The current divide between customers and retail sales is anticipated to remain similar over the 10-year period, with customers growing at an average annual rate of about 1.6 percent while retail sales increase by about 0.90 percent annually. Florida's electric utilities are projecting an increase in economic growth in the state, but at levels below those experienced before the financial crisis. The trends are showcased in Figure 7 below.



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Peak Demand

The aggregation of each individual customer's electric consumption must be met at all times by Florida's electric utilities to ensure reliable service. The time at which customers demand the most energy simultaneously is referred to as peak demand. While retail energy sales primarily vary the amount of fuel consumed by the electric utilities to deliver energy, peak demand determines the amount of generating capacity required to deliver that energy at a single moment in time.

A primary factor in this is seasonal weather patterns, with peak demands calculated separately for the summer and winter periods annually. The influence of residential customers is evident in the determination of these seasonal peaks, as they correspond to times of increased usage to meet home heating (winter) and cooling (summer) demand. Figure 8 below illustrates a daily load curve for a typical day for each season. In summer, air-conditioning needs increase throughout the day, climbing steadily until a peak is reached in the late afternoon and then declining into the evening. In winter, electric heat and electric water heating produce a higher base level of usage, with a large spike in the morning and a smaller spike in the evening.



Florida is typically a summer-peaking state, meaning that the summer peak demand generally exceeds winter peak demand, and therefore controls the amount of generation required. Higher temperatures in summer also reduce the efficiency of generation, with high water temperatures reducing the quality of cooling provided, and can sometimes limit the quantity as units may be required to operate at reduced power or go offline based on environmental permits. Conversely, in winter, utilities can take advantage of lower ambient air and water temperatures to produce more electricity from a power plant.

As daily load varies, so do seasonal loads. Figure 9 below illustrates this for 2015, showing the daily peak demand as a percentage of the annual peak demand for the reporting investor-owned

utilities combined. Typically, winter peaks are short events while summer demand tends to stay at near peak levels for longer periods. The periods between seasonal peaks are referred to as shoulder months, in which the utilities take advantage of lower demand to perform maintenance without impacting their ability to meet daily peak demand.



While the utilities assume normalized weather in forecasts of peak demand, during operation of the system, utilities continuously monitor the short-term weather patterns. Utilities adjust maintenance schedules to ensure the highest unit availability during the utility's projected peak demand, bringing units back online if necessary or delaying maintenance until after a weather system has passed.

Electric Vehicles

Utilities also examine other trends that may impact the amount of customer peak demand and energy consumption. This includes new sources of energy consumption, such as electric vehicles, which can be considered analogous to a home air conditioning system in terms of system load. At present, the reporting electric utilities estimate approximately 15,300 electric plug-in vehicles were operating in Florida at the end of 2015. The Florida Department of Highway Safety and Motor Vehicles lists the number of registered vehicles in Florida as of December 31, 2015, as 19.7 million vehicles, resulting in 0.077 percent penetration rate of electric vehicles of Florida's registered vehicle fleet.

Florida's electric utilities anticipate growth in the electric vehicle market, as illustrated in Table 2 below. Electric vehicles are anticipated to grow rapidly throughout the planning period, resulting in over 300,000 electric vehicles operating within the electric service territories by the end of 2025. The projected increase in electric vehicle ownership would result in approximately 2 percent share of Florida's vehicles being fueled by electricity.

Table 2: TYSP Utilities - Estimated Number of Electric Vehicles by Service Territory								
Year	FPL	DEF	TECO	GULF	JEA	OUC	TAL	Total
2015	10,466	2,819	1,052	450	386	-	88	15,261
2016	15,474	3,982	1,176	860	520	-	106	22,118
2017	23,683	5,683	1,345	1,450	683	-	137	32,981
2018	41,035	8,194	1,680	2,290	861	-	178	54,238
2019	61,552	11,626	1,820	3,410	1,066	-	232	79,706
2020	83,094	16,205	1,890	4,910	1,297	-	302	107,698
2021	108,023	21,732	1,941	6,900	1,558	-	392	140,546
2022	135,029	28,217	2,193	9,500	1,850	-	529	177,318
2023	167,437	35,502	2,633	12,910	2,175	-	715	221,372
2024	209,295	43,490	3,316	17,410	2,537	-	965	277,013
2025	251,154	52,180	4,615	23,660	2,938	-	1,351	335,898
Source: T	YSP 2016	Data Respo	nses					

In terms of energy consumed by electric vehicles, Table 3 below illustrates the estimates provided by the reporting utilities. The anticipated growth would result in an annual energy consumption of 1,424.3 GWh.

Table 3: TYSP Utilities - Estimated Electric Vehicle Annual Energy Consumption (GWh)								
Year	FPL	DEF	TECO	GULF	JEA	OUC	TAL	Total
2015	5.6	10.3	4.4	2.0	2.7	0.1	0.4	25.5
2016	28.2	14.3	5.0	3.8	3.8	-	0.5	55.6
2017	65.2	19.8	5.7	6.4	5.2	-	0.6	102.9
2018	143.4	27.9	7.1	10.1	6.9	-	0.8	196.2
2019	235.9	38.9	7.7	15.1	8.9	-	1.1	307.6
2020	333.0	53.5	8.0	21.7	11.4	-	1.4	429.0
2021	445.4	70.9	8.2	30.5	14.4	-	1.9	571.3
2022	567.2	91.8	9.3	42.0	17.9	-	2.5	730.7
2023	713.3	115.6	11.2	57.0	21.9	-	3.4	922.4
2024	902.0	142.3	14.1	76.9	26.7	-	4.6	1,166.6
2025	1,090.7	171.0	19.6	104.5	32.2	-	6.4	1,424.3
Source: T	YSP 2016	Data Respo	onses					

The effect of increased electric vehicle ownership on peak demand is more difficult to determine. While comparable in electric demand to a home air conditioning system, the time of charging and whether charging would be shifted away from periods of peak demand are uncertainties that must be clarified to determine impact on system peak. As electric vehicle ownership increases, the effects of electric vehicles on system peak should become clearer and be able to be addressed by electric utilities.

Demand-Side Management

Florida's electric utilities also must consider how the efficiency of customer energy consumption changes over the planning period. Changes in government mandates, such as building codes and appliance efficiency standards, reduce the amount of energy consumption for new construction and electric equipment. Electric customers, through the power of choice, can elect to engage in behaviors that decrease peak load or annual energy usage. Examples include, turning off lights and fans in vacant rooms, increasing thermostat settings, and purchasing appliances that go beyond efficiency standards. While a certain portion of customers will engage in these activities without incentives due to economic, aesthetic, or environmental concerns, other customers may lack information or require additional incentives. Demand-side management represents an area where Florida's electric utilities can empower and educate its customers to make choices that reduce peak load and annual energy consumption.

Florida Energy Efficiency and Conservation Act (FEECA)

The Florida Legislature has directed the Commission to encourage utilities to decrease the growth rates in seasonal peak demand and annual energy consumption by FEECA, which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Under FEECA, the Commission is required to set goals for seasonal demand and annual energy reduction for seven electric utilities, known as the FEECA Utilities. These include the five investor-owned electric utilities (including Florida Public Utility Company, which is a non-generating utility and therefore does not file a Ten-Year Site Plan) and two municipal electric utilities (JEA and OUC). The FEECA utilities represented approximately 86 percent of 2015 retail sales in Florida.

The FEECA utilities currently offer demand-side management programs for residential, commercial, and industrial customers. Energy audit programs are designed to provide an overview of customer energy usage and to evaluate conservation opportunities, including behavioral changes, low-cost measures customers can undertake themselves, and participation in utility-sponsored DSM programs.

The last FEECA goal-setting proceeding was completed in December 2014, establishing goals for the period 2015 through 2024. During 2015, the Commission reviewed the FEECA Utility's proposed DSM Plans to comply with the established goals, approving the plans with some modifications in July 2015. The 2016 Ten-Year Site Plans incorporate the impacts of the DSM Plans established by the Commission for the planning period.

DSM Programs

DSM Programs generally are divided into three categories: interruptible load, load management, and energy efficiency. The first two are considered dispatchable, and are collectively known as demand response, meaning that the utility can call upon them during a period of peak demand or other reliability concerns, but otherwise they are not utilized. In contrast, energy efficiency measures are considered passive and are always working to reduce customer demand and energy consumption.

Interruptible load is achieved through the use of agreements with large customers to allow the utility to interrupt the customer's load, reducing the generation required to meet system demand. Interrupted customers may use back-up generation to fill their energy needs, or cease operation

until the interruption has passed. A subtype of interruptible load is curtailable load, which allow the utility to interrupt only a portion of the customer's load. In exchange for the ability to interrupt these customers, the utility offers a discounted rate for energy or other credits which are paid for by all ratepayers.

Load management is similar to interruptible load, but focuses on smaller customers and targets individual appliances. The utility installs a device on an electric appliance, such as a water heater or air conditioner, which allows for remote deactivation for a short period of time. Load management activations tend to have less advanced notice than those for interruptible customers, but tend to be activated only for short periods and are cycled through groups of customers to reduce the impact to any single customer. Due to the focus on specific appliances, certain appliances would be more appropriate for addressing certain seasonal demands. For example, load management programs targeting air conditioning units would be more effective to reduce a summer peak, while water heaters are more effective for reducing a winter peak.

As of 2016, demand response available for reduction of peak load is 2,924 MW for summer peak and 2,885 MW for winter peak. Demand response is anticipated to increase to approximately 3,304 for summer peak and 3,178 for winter peak by the end of the planning period in 2025.

Energy efficiency or conservation measures also have an impact on peak demand, and due to their passive nature do not require activation by the utility. Conservation measures include improvements in a home or business' building envelope to reduce heating or cooling needs, or the installation of more efficient appliances. By installing additional insulation, energy-efficient windows or window films, and more efficient appliances, customers can reduce both their peak demand and annual energy consumption, leading to reductions in customer bills. Demand-side management programs work in conjunction with building codes and appliance efficiency standards to increase energy savings above the minimum required by local, state, or federal regulations. As of 2016, energy efficiency is responsible for peak load reduction of 4,024 MW for summer peak and 3,597 MW for winter peak. Energy efficiency is anticipated to increase to approximately 4,799 MW for summer peak and 4,165 MW for winter peak by the end of the planning period in 2025.

Forecast Load & Peak Demand

The historic and forecasted seasonal peak demand and annual energy consumption values for the State of Florida are illustrated below, in Figure 10. It should be noted, that the forecasts shown below are based upon normalized weather conditions, while the historic demand and energy values represent the actual impact of weather conditions on Florida's electric customers. Florida relies heavily upon both air conditioning in the summer and electric heating in the winter, so both seasons experience a great deal of variability due to severe weather conditions.

Demand-side management, including demand response and energy efficiency, along with selfservice generation is included in each figure for seasonal peak demand and annual energy for load. The total demand or total energy for load represents what otherwise would need to be served if not for the impact of these programs and self-service generators. The net firm demand is used as a planning number for the calculation of generating reserves and determination of generation needs for Florida's electric utilities. Demand response is included in Figure 10 below, in two different ways based upon the time period considered. For historic values of seasonal demand, the actual rates of demand response activation are shown, not the full amount demand response that was available at the time. Overall, demand response has only been partially activated as sufficient generation assets were available during the annual peak. Residential load management has been called upon to a limited degree during peak periods, with a lesser amount of interruptible load activated. The primary exception to this trend was the summer of 2008 and winter of 2009, when a larger portion of the available demand response resources were called upon.

For forecast values of seasonal demand, it is assumed that all demand response resources will be activated during peak. The assumption of all demand response being activated reduces generation planning need. Based on operating conditions in the future, if an electric utility has sufficient generating units, and it is economical to serve all customers load demand, response would not be activated or only partially activated in the future.

As previously discussed, Florida is normally a summer-peaking state. Only three of the past ten years have had higher winter net firm demand than summer, and all ten of the forecast years are anticipated to be summer peaking. Based upon current forecasts using normalized weather data, Florida's electric utilities do not anticipate exceeding the winter 2009 peak during the planning period.


Figure 10: State of Florida - Historic & Forecast Seasonal Peak Demand & Annual Energy

Forecast Methodology

Florida's electric utilities perform forecasts of peak demand and annual energy sales using various forecasting models, including econometric and end-use models, and other forecasting techniques such as surveys. In the development of econometric models, the utilities use historical data sets including dependent variables (e.g. summer peak demand per customer, residential energy use per customer) and independent variables (e.g. cooling degree days, real personal income, etc.) to infer relationships between the two types of variables. These historical relationships, combined with available forecasts of the independent variables and the utilities' forecasts of customers, are then used to forecast the peak demand and energy sales. For some customer classes, such as industrial customers, surveys may be conducted to determine the customers' expectations for their own future electricity consumption.

The forecasts also account for demand-side management programs. Sales models are prepared by revenue class (e.g. residential, small and large commercial, small and large industrial, etc.). Commonly, the results of the models must be adjusted to take into account exogenous impacts, such as the impact of the recent growth in plug-in electric vehicles and distributed generation.

End-use models are sometimes used to project energy use in conjunction with econometric models. End use models are used to capture trends in appliance and equipment saturation and efficiency, as well as building size and thermal efficiency, on residential and commercial energy use. If such end use models are not used, the econometric models for energy often include an index comprised of efficiency standards for air conditioning, heating, and appliances, as well as construction codes for recently built homes and commercial buildings.

Florida's electric utilities rely upon data sourced from public and private entities for historic and forecast values of specific independent variables used in econometric modeling. Public resources such as the University of Florida's Bureau of Economic and Business Research, which provides county-level data on population growth, and the U.S. Department of Commerce's Bureau of Labor Statistics, which publishes the Consumer Price Index, are utilized along with private forecasts for economic growth from macroeconomic experts, such as Moody's Analytics. By combining historic and forecast macroeconomic data with customer and climate data, Florida's electric utilities project future load conditions.

The various forecast models and techniques used by Florida's electric utilities are commonly used throughout the industry, and each utility has developed its own individualized approach to projecting load. The resulting forecasts allow each electric utility to evaluate its individual needs for new generation, transmission, and distribution resources to meet customers' current and future needs reliably and affordably.

For each reporting electric utility, the Commission reviewed the historic forecast accuracy of past retail energy sales forecasts. The review methodology, previously used by the Commission, involves comparing actual retail sales for a given year to energy sales forecasts made three, four, and five years prior. For example, the actual 2015 retail energy sales were compared to the forecasts made in 2012, 2011, and 2010. These differences, expressed as a percentage error rate, are used to determine each utility's historic forecast accuracy using a five-year rolling average. An average error with a negative value indicates an under-forecast, while a positive value

represents an over-forecast. An absolute average error provides an indication of the total magnitude of error, regardless of the tendency to under or over forecast.

For the 2016 Ten-Year Site Plans, determining the accuracy of the five-year rolling average forecasts involves comparing the actual retail energy sales for the period 2015 through 2011 to forecasts made between 2012 and 2006. As discussed previously, the period before the financial crisis, known as the Great Recession, experienced a higher annual growth rate for retail energy sales than the post-crisis period. As most electric utilities and macroeconomic forecasters did not predict the financial crisis, the economic impact and its resulting effect on retail energy sales of Florida's electric utilities was not included in these projections. Therefore, the use of a metric that compares pre-crisis forecasts with post-crisis actual data has a high rate of error.

Table 4 below shows that the forecast errors are increasing with time starting in 2011 due to the unexpected impact of the Great Recession and its impact on retail energy sales in Florida. However, the forecast errors have started to return to lower levels as utility retail sales forecasts include more post-recession years. This was indicated by the data provided in last year's TYSPs; and it is confirmed by the data provided in the current TYSPs. The forecasting error rates (both average and absolute average) generated by comparing actual 2015 retail energy sales to the 2014 forecast of 2015 energy sales are further reduced from the error rates generated by comparing actual 2014 sales to the 2013 forecast of 2014 sales.

Table 4:	TYSP	Utiliti	es - Accı	iracy	of Re	tail Energy Sales Forecasts	
		Π.	T 7	-			

TVSP Five-Year		Forecast	Forecast Error (%)		
Year	Analysis Period	Years Analyzed	Average	Absolute Average	
2011	2010 - 2006	2007-2001	8.28%	8.29%	
2012	2011 - 2007	2008-2002	11.93%	11.93%	
2013	2012 - 2008	2009-2003	15.13%	15.13%	
2014	2013 - 2009	2010-2004	16.16%	16.16%	
2015	2014 - 2010	2011-2005	14.90%	14.90%	
2016	2015 - 2011	2012-2006	12.48%	12.48%	

Source: 2001-2016 Ten-Year Site Plans

To verify whether more recent forecasts lowered the error rates, an additional analysis was conducted to determine with more detail, the source of high error rates in terms of forecast timing. Table 5 below provides the forecast error rate for forecasts made between one and six years prior, along with the average and absolute average error rates for the three- to five-year period used in the analysis above.

As displayed in Table 5 below the companies' retail energy sales forecasts show a consistent positive error rate beginning in 2007 and extending through 2014 for forecasts prepared two to six years prior. However, 2014 sales forecasted in 2010 and 2011, reveal that three and four year error rates (6.10 percent and 5.73 percent, respectively) have declined considerably compared to the three and four year forecast error rates associated with 2010-2013 sales. The error rates calculated based on the data provided in the current TYSPs continues showing across the board

declines in forecast error rates made between one and six years prior, with the one-year ahead forecast showing a negative error rate (under-forecast).

a	ble 5: 1	YSP Util	ities - A	ccuracy	of Retail	l Energy	Sales Fo	orecasts – Ai	nnual Analy
			Annua	l Forecast	Error Ra	te (%)		3-5 Year I	Error (%)
	Year			Years	Prior			Average	Absolute
		6	5	4	3	2	1	Average	Average
	2006	-3.29%	-0.03%	1.03%	2.30%	2.43%	2.37%	1.10%	1.12%
	2007	0.57%	2.26%	3.49%	3.59%	4.20%	3.05%	3.11%	3.11%
	2008	7.02%	8.40%	8.56%	9.97%	9.24%	8.34%	8.98%	8.98%
	2009	11.95%	12.15%	14.48%	13.91%	12.68%	10.18%	13.51%	13.51%
	2010	12.93%	15.57%	14.89%	13.70%	10.55%	-0.73%	14.72%	14.72%
	2011	21.56%	20.79%	20.09%	17.02%	3.79%	0.08%	19.30%	19.30%
	2012	26.31%	25.97%	23.04%	8.47%	3.90%	3.71%	19.16%	19.16%
	2013	28.55%	26.29%	10.00%	5.98%	5.58%	2.97%	14.09%	14.09%
	2014	27.28%	9.80%	6.10%	5.73%	2.84%	2.21%	7.21%	7.21%
	2015	7.29%	3.63%	3.23%	1.02%	0.00%	-1.17%	2.63%	2.63%

precasts – Annual Analysis Table 5: TYSP Utilities - Accuracy of Dotoil En Cale E.

Source: 2001-2016 Ten-Year Site Plans

Barring any unforeseen economic crises or atypical weather patterns, average forecasted energy sales error rates in the next few years are likely to be more reflective of the error rates shown for 2015 in Table 5 than the significantly higher error rates shown in earlier years. It is important to recognize that the dynamic nature of the economy and the weather continue to present a degree of uncertainty for Florida utilities' load forecasts, ultimately impacting the accuracy of such forecasts.

Renewable Generation

Pursuant to Section 366.91, F.S., it is in the public interest to promote the development of renewable energy resources in Florida. Section 366.91(2)(d), F.S., defines renewable energy in part, as follows:

"Renewable energy" means electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power.

Although not considered a traditional renewable resource, some industrial plants take advantage of waste heat, produced in production processes, to also provide electrical power via cogeneration. Phosphate fertilizer plants, which produce large amounts of heat in the manufacturing of phosphate from the input stocks of sulfuric acid, are a notable example of this type of renewable resource. The Section 366.91(2)(d), F.S., definition also includes the following language which recognizes the aforementioned cogeneration process:

The term [Renewable Energy] includes the alternative energy resource, waste heat, from sulfuric acid manufacturing operations and electrical energy produced using pipeline-quality synthetic gas produced from waste petroleum coke with carbon capture and sequestration.

Existing Renewable Resources

Currently, renewable energy facilities provide approximately 1,860 MW of firm and non-firm generation capacity, which represents 3.1 percent of Florida's overall generation capacity of 58,421 MW in 2015. Table 6 below summarizes the contribution by renewable type of Florida's existing renewable energy sources.

Table 6: State of Flor	rida - Existing R	enewable Reso
Renewable	Гуре МW	% Total
Biomass	582	31.3%
Municipal Solid V	Vaste 545	29.3%
Waste Heat	310	16.7%
Solar	263	14.2%
Landfill Gas	87	4.7%
Hydro	63	3.4%
Wind ³	10	0.5%
Renewable Total	1,860	100.00%
ource: FRCC 2016 Load & Resource P	lan and TYSP Ut	ilities Data Res

³JEA's wind resources are not present in-state.

Of the total 1,860 MW of renewable generation, approximately 598 MW are considered firm, based on either operational characteristics or contractual agreement. Firm renewable generation can be relied on to serve customers and can contribute toward the deferral of new fossil fueled power plant construction. Solar generation contributes 34 MW to this total, based upon the coincidence of solar generation and summer peak demand. Changes in timing of peak demand may influence the firm contributions of renewable resources such as solar and wind.

The remaining renewable generation can generate energy on an as-available basis or for internal use (self-service). As-available energy is considered non-firm, and cannot be counted on for reliability purposes; however, it can contribute to the avoidance of burning fossil fuels in existing generators. Self-service generation reduces demand on Florida's utilities.

Non-Utility Renewable Generation

The majority of Florida's existing renewable energy generation, approximately 89 percent, comes from non-utility generators. In 1978, the US Congress enacted the Public Utility Regulatory Policies Act (PURPA). PURPA requires utilities to purchase electricity from cogeneration facilities and renewable energy power plants with a capacity no greater than 80 MW (collectively referred to as Qualifying Facilities or QFs). PURPA required utilities to buy electricity from qualifying QFs at the utility's full avoided cost. These costs are defined in Section 366.051, F.S., which provides in part that:

A utility's "full avoided costs" are the incremental costs to the utility of the electric energy or capacity, or both, which, but for the purchase from cogenerators or small power producers, such utility would generate itself or purchase from another source.

If a renewable energy generator can meet certain deliverability requirements, it can be paid for its capacity and energy output under a firm contract. Rule 25-17.250, F.A.C., requires each IOU to establish a standard offer contract with timing and rate of payments based on each fossil-fueled generating unit type identified in the utility's TYSP. In order to promote renewable energy generation, the Commission requires the IOUs to offer multiple options for capacity payments, including the options to receive early (prior to the in-service date of the avoided-unit) or levelized payments. The different payment options allow renewable energy providers the option to select the payment option that best fits its financing requirements, and provides a basis from which negotiated contracts can be developed.

As previously discussed, large amounts of renewable energy is generated on an as-available basis. As-available energy is energy produced and sold by a renewable energy generator on an hour-by-hour basis for which contractual commitments as to the quantity and time of delivery are not required. As-available energy is purchased at a rate equal to the utility's hourly incremental system fuel cost, which reflects the highest fuel cost of generation each hour.

Customer Owned Renewable Generation

With respect to customer-owned renewable generation, Rule 25-6.065, F.A.C., requires the IOUs to offer net metering for all types of renewable generation up to 2 MW in capacity and a standard interconnection agreement with an expedited interconnection process. Net metering allows a customer, with renewable generation capability, to offset their energy usage. In 2008, the effective year of Rule 25-6.065, F.A.C., customer owned renewable generation accounted for 3 MW of renewable capacity. As of the end of 2015, approximately 108 MW of renewable capacity from nearly 11,650 systems has been installed statewide. Table 7 below summarizes the growth of customer owned renewable generation interconnections. Almost all installations are solar, with non-solar generation accounting for only 35 installations and 5.7 MW of installed capacity. The renewable generators in this category include wind turbines and anaerobic digesters.

	Table 7: State of Florida - Customer-Owned Renewable Growth							
Year	2008	2009	2010	2011	2012	2013	2014	2015
Number of Installations	577	1,625	2,833	3,994	5,302	6,697	8,581	11,626
Installed Capacity (MW)	2.8	13.0	19.9	28.4	42.2	63.0	79.8	107.5

Source: Annual Utility Reports

Utility-Owned Renewable Generation

Utility-owned renewable generation also contributes to the State's total renewable capacity. The majority of this generation is from solar facilities. Due to the intermittent nature of solar resources, capacity from these facilities has previously been considered non-firm for planning purposes.

In 2008, Section 366.92(4), F.S., was enacted and provides, in part, the following:

In order to demonstrate the feasibility and viability of clean energy systems, the commission shall provide for full cost recovery under the environmental cost-recovery clause of all reasonable and prudent costs incurred by a provider for renewable energy projects that are zero greenhouse gas emitting at the point of the generation, up to a total of 110 MW statewide.

In 2008, the Commission approved a petition by FPL seeking installation of the full 110 MW across three solar energy facilities. The solar projects consisted of, a pair of solar PV facilities and a single solar thermal facility. In response to staff interrogatories, FPL estimated that the three solar facilities would cost an additional \$573 million, above traditional generation costs over the life of the facilities. In 2012, Section 366.92, F.S., was revised and no longer includes the passage described above.

Based on actual data provided by FPL, the combined cost of generation of the three solar facilities was \$0.41/kWh in 2016. These facilities make up a significant portion of the utility owned renewable generation. Since full operation began, the two solar PV facilities have

operated largely as expected; however, the solar thermal facility has experienced multiple outages which have hindered its performance. In FPL's 2016 TYSP, FPL included that the Desoto and Space Coast solar facilities contributed approximately 46 percent and 32 percent, respectively, of the system's installed capacity to summer peak demand. No contribution to winter peak demand as determined from either facility.

Hydroelectric units at two sites, one owned by the City of Tallahassee Utilities, and one operated by the federal government, supply 63 MW of renewable capacity. Due to operational constraints, the City of Tallahassee does not consider its 12.3 MW of hydroelectric generation firm. Because of Florida's geography, however, new hydroelectric power generation is largely limited.

Planned Renewable Resources

Florida's utilities plan to construct or purchase an additional 2,016 MW of renewable generation over the 10-year planning period, an increase from last year's estimated 1,566 MW projections. Figure 11 below summarizes the existing and projected renewable capacity by generation type. Solar generation is projected to have the greatest increase over the planning horizon.



Of the 2,016 MW of planned renewable capacity, 365 MW is projected to be from firm resources with 124 MW of that firm amount coming from solar generation. The projected firm capacity additions are from a combination of renewable contracts with non-utility generators, primarily biomass, and several utility-owned solar facilities. The remaining planned capacity from renewable resources is projected to be from non-firm resources.

⁴JEA and Gulf's wind resources are not present in-state.

For some existing renewable facilities, contracts for firm capacity are projected to expire within the 10-year planning horizon. If new contracts are signed in the future to replace those that expire, these resources will once again be included in the state's capacity mix to serve future demand. If these contracts are not extended, the renewable facilities could still deliver energy on an as-available basis.

As noted above, solar generation is anticipated to increase significantly over the 10-year period, with a total of 1,586 MW to be installed. This consists of 1,102 MW of utility-owned solar, 184 MW of contracted solar and 300 MW of as-available energy contract solar facilities. Table 8 below lists some of the utility-scale (greater than 10 MW) solar installations with in-service dates within the planning period.

Gulf has entered into purchase power agreements linked to 272 MW of wind energy produced by facilities located in Oklahoma. While the energy from the facilities may not be delivered to Gulf's system, the renewable attributes for their output are retained by the utility for the benefit of Gulf's customers.

		Table 8: TYSP Utilities - Planned	Solar Installations	
Year	Utility	Facility Name	Туре	Capacity (MW)
2016	FPL	Babcock Solar Energy Center	Utility Owned	74.5
2016	FPL	Citrus Solar Energy Center	Utility Owned	74.5
2016	FPL	Manatee Solar	Utility Owned	74.5
2016	OUC	Stanton Solar Phase 2	Purchased	12
			2016 Subtotal	235.5
2017	GULF	Gulf Coast Solar Center I Eglin	Purchased	30
2017	GULF	Gulf Coast Solar Center II Holley	Purchased	40
2017	GULF	Gulf Coast Solar Center III Saufley	Purchased	50
2017	DEF	Solar 3	Utility Owned	10
2017	DEF	Solar 4	Utility Owned	10
2017	TAL	Airport 1	Purchased	20
2017	TECO	Big Bend	Utility Owned	18
			2017 Subtotal	178
2018	DEF	Solar 5	Utility Owned	10
			2018 Subtotal	10
2019	DEF	Solar 6&7	Utility Owned	50
			2019 Subtotal	50
2020	DEF	Solar 8 & 9	Utility Owned	130
2020	FPL	Unsited Projects	Utility Owned	300
			2020 Subtotal	430
2021	DEF	Solar 10	Utility Owned	35
			2021 Subtotal	35
2022	DEF	Solar 11	Utility Owned	50
			2022 Subtotal	50
2023	DEF	Solar 12	Utility Owned	75
			2023 Subtotal	75
2024	DEF	Solar 13 & 14	Utility Owned	125
			2024 Subtotal	125
2025	DEF	Solar 15	Utility Owned	50
			2025 Subtotal	50
TBD	DEF	Blue Chip Energy Lake Mary	Purchased	10
TBD	DEF	Blue Chip Energy Sorrento	Purchased	40
TBD	DEF	National Solar Gadsden	Purchased	50
TBD	DEF	National Solar Hardee	Purchased	50
TBD	DEF	National Solar Suwannee	Purchased	50
TBD	DEF	National Solar Highlands	Purchased	50
TBD	DEF	National Solar Osceola	Purchased	50
			TBD Subtotal	300

Source: 2016 FRCC Load & Resource Plan, TYSP Utilities Data Responses

Renewable Outlook

Florida's renewable generation is projected to increase over the planning period. Some utilities are including a portion of solar capacity as a firm resource for reliability considerations. Reasons given for these additions are the continued reduction in price of solar facilities, availability of utility property with access to the grid, and actual performance data from FPL's pilot program. If these conditions remain, the cost-effective forms of renewable generation will continue to improve the state's fuel diversity and reduce dependence on fossil fuels.

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Traditional Generation

While renewable generation increases its contribution to the state's generating capacity, a majority of generation is projected to come from traditional sources, such as fossil-fueled steam and turbine generators, that have been added to Florida's electric grid over the last several decades. Due to forecasted increases in peak demand, further traditional resources are anticipated over the planning period.

Florida's electric utilities have historically relied upon several different fuel types to serve customer load. Previous to the oil embargo, Florida used oil-fired generation as its primary source of electricity until the increase in oil prices made this undesirable. Since that time, Florida's electric utilities have sought a variety of other fuel sources to diversify the state's generation fleet and more reliably and affordably serve customers. Numerous factors, including swings in fuel prices, availability, environmental concerns, and other factors have resulted in a variety of capacity on Florida's electric grid. Solid fuels, such as coal and nuclear, increased during the shift away from oil-fired generation, and more recently natural gas has emerged as the dominant fuel type in Florida.

Existing Generation

Florida's generating fleet includes incremental new additions to a historic base fleet, with units retiring as they become uneconomical to operate or maintain. Currently, Florida's existing capacity ranges greatly in age and fuel type, and legacy investments continue. The weighted average age of Florida's generating units is 23 years. While the original commercial in-service date may be in excess of 60 years for some units, they are constantly maintained as necessary in order to ensure safe and reliable operation, including uprates from existing capacity, which may have been added after the original in-service date. Figure 12 below illustrates the decade current operating generating capacity was originally added to the grid, with the largest additions occurring in the 2000s.



The existing generating fleet will be impacted by several events over the planning period. New and proposed environmental regulations may require changes in unit dispatch, fuel switching, or installation of pollution control equipment which may reduce net capacity. Modernizations will allow more efficient resources to replace older generation, while potentially reusing power plant assets such as transmission and other facilities, switching to more economic fuel types, or uprates at existing facilities to improve power output. Lastly, retirements of units which can no longer be economically operated and maintained or meet environmental requirements will reduce the existing generation.

Impact of EPA Rules

In addition to maintaining a fuel efficient and diverse fleet, Florida's utilities must also comply with environmental requirements that impose incremental costs or operational constraints. During the planning period, six EPA rules were anticipated to affect electric generation in Florida:

- Carbon Pollution Emissions Standards for New, Modified and Reconstructed Secondary Sources: Electric Utility Generating Units Sets carbon dioxide emissions limits for new, modified or reconstructed electric generators. These limits vary by type of fuel (coal or natural gas). New units are those built after January 18, 2014. Units that undergo modifications or reconstructions after June 18, 2014, that materially alter their air emissions are subject to the specified limits. This rule has been appealed.
- Carbon Pollution Emission Guideline for Existing Electric Generating Units (Clean Power Plan) Requires each state to submit a plan to EPA that outlines how the state's existing electric generation fleet over 25 megawatts will meet a series of goals, in terms of pounds of carbon dioxide emitted per generated megawatt-hour, to reduce the state's carbon dioxide emissions. The guidelines include increased use of renewable generation and decreased use of coal-fired generation by 2030. This rule has been stayed pending an appeal review.
- Mercury and Air Toxics Standards (MATS) Sets limits for air emissions from existing and new coal- and oil-fired electric generators with a capacity greater than 25 megawatts. Covered emissions include: mercury and other metals, acid gases, and organic air toxics for all generators, as well as particulate matter, sulfur dioxide, and nitrogen oxide from new and modified coal and oil units.
- Cross-State Air Pollution Rule (CSAPR) Requires certain states to reduce air emissions that contribute to ozone and/or fine particulate pollution in other states. The rule applies to all fossil-fueled (i.e., coal, oil, and natural gas) electric generators with a capacity over 25 megawatts within the upwind states. Originally, the rule included Florida. However, the final rule, issued September 7, 2016, removes North Carolina, South Carolina and Florida from the program because modeling for the final rule indicates that these states do not contribute significantly to ozone air quality problems in downwind states.
- Cooling Water Intake Structures (CWIS) Sets impingement standards to reduce harm to aquatic wildlife pinned against cooling water intake structures at electric generating

facilities. All electric generators that use state or federal waters for cooling with an intake velocity of at least two million gallons per day must meet impingement standards. Generating units with higher intake velocity may have additional requirements to reduce the damage to aquatic wildlife due to entrapment in the cooling water system.

• Coal Combustion Residuals (CCR) - Requires liners and ground monitoring to be installed on new landfills in which coal ash is deposited.

Each utility will need to evaluate whether these additional costs or operational limitations allow the continued economic operation of each affected unit, and whether installation of emissions control equipment, fuel switching, or retirement is the proper course of action.

Modernization and Efficiency Improvements

Modernizations involve removing existing generator units that may no longer be economical to operate, such as oil-fired steam units, and reusing the power plant site's transmission or fuel handling facilities with a new set of generating units. The modernization of existing plant sites, allows for significant improvement in both performance and emissions, typically at a lower price than new construction at a greenfield site. Not all sites are candidates for modernization due to site layout and other concerns, and to minimize rate impacts, modernization of existing units should be considered along with new construction at greenfield sites.

The Commission has previously granted determinations of need for several conversations of oilfired steam units to natural gas-fired combined cycle units, including FPL's Cape Canaveral, Riviera, and Port Everglades power plants. DEF has also conducted a conversion of its Bartow power plant, but this did not require a determination of need from the Commission.

Utilities also plan several efficiency improvements to existing generating units. An example is the conversion of existing simple cycle combustion turbines into a combined cycle unit, which captures the waste heat and uses it to generate additional electricity using a steam turbine. The Commission has granted a determination of need for the conversion of TECO's Polk Units 2 through 5 to a single combined cycle unit.⁵ FPL plans on upgrading its existing combined cycle fleet by improving the performance of the integrated combustion turbines at many of its current and planned power plants. By 2018, DEF plans to increase the summer capacity rating at the Hines Energy Center through the installation of Inlet Chilling.

Planned Retirements

Power plant retirements occur when the electric utility is unable to economically operate or maintain a generating unit due to environmental, economic, or technical concerns. Table 9 below lists the 4,610 MW of existing generation that is scheduled to be retired during the planning period, a majority of which are natural gas-fired peaking units. Approximately 1,160 MW of the planned retirements are three dozen small peaking units at two power plant sites operated by FPL.

⁵Order No. PSC-13-0014-FOF-EI, issued January 8, 2013, in Docket No. 120234-EI, *In re: Petition to determine need for Polk 2-5 combined cycle conversion, by Tampa Electric Company.*

	Table 9: State of Florida - Electric Generating Units to be Retired							
Year	Utility Name	Plant Name & Unit Number	Unit Type	Fuel Type	Net Capacity (MW)			
2016	DEE	G E Turner P1 - P4	СТ	Distillate Fuel Oil	132 0			
2016	GPC	Lansing Smith 2	Steam	Coal	0.0			
2016	FPL	Turkey Point 1	Steam	Residual Fuel Oil	396.0			
2016	DEF	Rio Pinar 1	СТ	Distillate Fuel Oil	12.0			
2016	FPL	Ft. Myers 1 - 10	СТ	Distillate Fuel Oil	540.0			
2016	FPL	Lauderdale 1 - 22	СТ	Natural Gas	754.0			
2016	FPL	Port Everglades 1 - 12	СТ	Natural Gas	408.0			
		2016 Subtotal			2,242.0			
2017	DEF	Suwannee River 1 - 2	Steam	Natural Gas	57.0			
2017	FPL	Cedar Bay	Steam	Coal	250.0			
2017	TAL	Hopkins GT1	СТ	Natural Gas	12.0			
2017	TAL	Purdom GT1 & GT2	СТ	Natural Gas	20.0			
		2017 Subtotal			339.0			
2018	DEF	Crystal River 1 & 2	Steam	Coal	740.0			
2018	DEF	Suwannee River 3	Steam	Natural Gas	71.0			
2018	GPC	Pea Ridge 1 - 3	СТ	Natural Gas	12.0			
2018	TAL	Hopkins GT2	СТ	Natural Gas	24.0			
		2018 Subtotal			847.0			
2019	JEA	Northside 3 [Reserve Storage]	Steam	Natural Gas	524.0			
		2019 Subtotal			524.0			
2020	DEF	Higgins 1 - 4	СТ	Natural Gas	459.0			
2020	DEF	Avon Park 1	СТ	Natural Gas	24.0			
2020	DEF	Avon Park 2	СТ	Distillate Fuel Oil	24.0			
		2020 Subtotal			507.0			
2021	TAL	Hopkins 1	Steam	Natural Gas	76.0			
		2021 Subtotal			76.0			
2022	GRU	Deerhaven FS01	Steam	Natural Gas	75.0			
		2022 Subtotal			75.0			
		Total Retirements			4,610			
Sourc	e [.] 2016 '	Ten-Year Site Plans						

A notable retirement is DEF's Crystal River Units 1 and 2. Originally scheduled to retire in 2016, the retirement of these units have been delayed until 2018. This delay is due in part to a temporary averaging of emissions across the existing four units at the Crystal River site to meet environmental regulations, as Crystal River Units 4 and 5 have pollution controls installed.

Some retired units will continue operation in a different form. FPL intends to retire Turkey Point 1, a large oil-fired steam unit, and convert it to a synchronous condenser to support the transmission system and provide voltage regulation. FPL previously converted Turkey Point 2 to operate as a synchronous condenser.

Reliability Requirements

Florida's electric utilities are expected to have enough generating assets available at the time of peak demand to meet forecasted customer demand. If utilities only had sufficient generating capacity to meet forecasted peak demand, then potential instabilities could occur if customer demand exceeds the forecast, or if generating units are unavailable due to maintenance or forced outages. To address these circumstances, utilities are required to maintain additional planned generating capacity above the forecast customer demand, referred to as the reserve margin.

Electric utilities within the Florida Reliability Coordinating Council region, which consists of Peninsular Florida, must maintain a minimum of 15 percent reserve margin for planning purposes. Certain utilities have elected to have a higher reserve margin, either on an annual or seasonal basis. The three largest reporting electric utilities, FPL, DEF, and TECO, are party to a stipulation approved by the Commission that utilizes a 20 percent reserve margin for planning.

While Florida's electric utilities are separately responsible for maintaining an adequate planning reserve margin, a statewide view illustrates the degree to which capacity may be available for purchases during periods of high demand or unit outages. Figure 13 below is a projection of the statewide seasonal reserve margin including all proposed power plants.



Figure 13: State of Florida - Projected Reserve Margin by Season

Role of Demand Response in Reserve Margin

The Commission also considers the planning reserve margin without demand response. As illustrated above in Figure 13, the statewide seasonal reserve margin exceeds the FRCC's required 15 percent planning reserve margin without activation of demand response. Demand response activation increases the reserve margin in summer by 7.5 percent on average, and represents 25 percent of the planning reserve margin.

Demand response participants receive discounted rates or credits regardless of activation, with these costs recovered from all ratepayers. Because of the voluntary nature of demand response, a concern exists that a heavy reliance upon this resource would make participants eschew the discounted rates or credits for firm service. For interruptible customers, participants must provide notice that they intend to leave the demand response program, with a notice period of three or more years being typical. For load management participants, usually residential or small commercial customers, no advanced notice is typically required to leave. Historically, demand

response participants have rarely been called upon during the peak hour, but are more frequently called upon during off-peak periods due to unusual weather conditions.

Fuel Price Forecast

Fuel price is an important economic factor affecting the dispatch of the existing generating fleet and the selection of new generating units. In general, the capital cost of a power plant is inversely proportional to the cost of the fuel used to generate electricity from that unit. The major fuels consumed by Florida's electric utilities are natural gas, coal, uranium, and oil. Figure 14 below illustrates the weighted average fuel price history and forecasts for the reporting electric utilities. While there has been a recent projected decrease in fuel oil prices, it remains the most expensive fuel and suitable primarily for backup and peaking purposes only.



From 2003 to 2005, the price of natural gas was substantially higher than utilities had forecast. This natural gas price volatility led to concern regarding escalating customer bills and an expectation that natural gas prices would remain high. As a result, Florida's electric utilities began making plans to build coal-fired units rather than continuing to increase the reliance on natural gas. Concerns regarding potential environmental regulations, and other projected costs, lead to this coal-fired generation to not materialize. Traditionally, coal was the lowest cost fuel besides uranium and was dispatched before most natural gas-fired units. While natural gas-fired units have the advantage of a lower heat rate, and therefore consume less units of thermal energy per unit of electrical energy produced, the fuel price differential allowed coal to remain dominant until 2008.

As shown below in Figure 15, the price of natural gas declined rapidly after the financial crisis, and is forecasted to remain at historically low levels. The smaller differential and higher efficiency of natural gas has shifted the dispatch order, with natural gas units displacing some coal units. The trend has also encouraged utilities to modify existing units to be capable of burning natural gas, either as a starter fuel, supplemental fuel, or primary fuel.



Fuel Diversity

Natural gas has risen to become the dominant fuel in Florida within the last 10 years, displacing coal, and since 2010 has generated more net energy for load than all other fuels combined. As Figure 16 below illustrates, natural gas is the source of approximately 63 percent of electric energy consumed in Florida, down from its peak in 2012 of 65 percent. The 2012 spike in usage was associated with extended outages at FPL's nuclear plants for uprates. Natural gas generation is anticipated to remain somewhat steady at its current level until the end of the planning period.



Figure 16: State of Florida - Natural Gas Contribution to Energy Consumption

Because a balanced fuel supply can enhance system reliability and mitigate the effects of volatility in fuel price fluctuations, it is important that utilities have a level of flexibility in their generation mix. Maintaining fuel diversity on Florida's system faces several difficulties. Existing coal units will require additional emissions control equipment leading to reduced output, or retirement if the emissions controls are uneconomic to install or operate. New solid fuel generating units such as nuclear and coal have long lead times and high capital costs. New coal units face challenges relating to new environmental compliance requirements, making it unlikely they could be permitted without novel emissions control technology.

Figure 17 below shows Florida's historic and forecast percent net energy for load by fuel type for the actual years 2005 and 2015, and forecast year 2025. Oil has declined significantly, with its uses reduced to start-up fuel, peaking, and back-up for dual-fuel units in case of a fuel outage. Nuclear generation was reduced beginning in 2010 by the outage and eventual retirement of Crystal River 3 and extended outages for uprates at FPL's St. Lucie and Turkey Point power plants. The resulting capacity leaves Florida's contribution from nuclear approximately the same even with the loss of one of five nuclear units. While coal generation has declined somewhat, it is expected to rebound slightly and remain at a plateau throughout the planning period. Natural gas has been the primary fuel used to meet the growth energy consumption, and this trend is anticipated to continue throughout the planning period.



Based on 2014 Energy Information Administration (EIA) data, Florida ranks fourth place in terms of the total volume natural gas consumption compared to the rest of the United States. For

volume of natural gas consumed for electric generation, Florida ranks second, behind Texas.

Florida's percentage of natural gas consumption for electric generation is the highest in the country, with 90 percent of all natural gas consumed in the state for electricity. However, these figures do not consider population. On a per capita basis, Florida's total consumption of natural gas ranks thirtieth, while natural gas consumption for electricity ranks sixth. Natural gas is not used as a heating fuel in most of Florida's homes and businesses, which rely instead upon electricity that is increasingly being generated by natural gas. This leads to Florida's per capita consumption of natural gas for electricity. As Florida has very little natural gas production and no gas storage capacity, the State is reliant upon out-of-state production and storage to satisfy the growing electric demands of the state.

New Generation Planned

Current demand and energy forecasts continue to indicate that in spite of increased levels of conservation, energy efficiency, renewable generation, and existing traditional generation resources, the need for additional generating capacity still exists. While reductions in demand have been significant, the total demand for electricity is expected to increase, making the addition of traditional generating units necessary to satisfy reliability requirements and provide sufficient electric energy to Florida's consumers. Because any capacity addition has certain economic impacts based on the capital required for the project, and due to increasing environmental concerns relating to solid fuel-fired generating units, Florida's utilities must carefully weigh the factors involved in selecting a supply-side resource for future traditional generation projects.

In addition to traditional economic analyses, utilities also consider several strategic factors, such as fuel availability, generation mix, and environmental compliance prior to selecting a new supply-side resource. Limited supplies, access to water or rail delivery points, pipeline capacity, water supply and consumption, land area limitations, cost of environmental controls, and fluctuating fuel costs are all important considerations to the utilities' IRP process.

Figure 18 below illustrates the present and future aggregate capacity mix. The capacity values in Figure 18 incorporate all proposed additions, changes, and retirements contained in the reporting utilities' 2016 Ten-Year Site Plans and the FRCC's 2016 Load and Resource Plan.



Source: 2016 FRCC Load & Resource Plan and TYSP Utilities Data Responses

New Power Plants by Fuel Type

Nuclear

Nuclear capacity, while an alternative to natural gas-fired generation, is capital-intensive and requires a long lead time to construct. FPL has two nuclear projects at Turkey Point that were moved out of the planning horizon for the 2016 TYSP. FPL had previously uprated its existing four nuclear generating units, with the last uprate completed in early 2013. DEF continues its efforts to obtain a combined operating license from the Nuclear Regulatory Commission, for two nuclear units, Levy 1 and 2, but has not included them in their planning at this time.

Natural Gas

Excluding renewable and nuclear generation uprates, all remaining new power plants are natural gas-fired combustion turbines or combined cycle units. Combustion turbines run in simple cycle mode as peaking units represent the third most abundant type of generating capacity, behind only coal-fired steam generation. Because combustion turbines are not a form of steam generation, unless part of a combined cycle unit, they do not require siting under the Power Plant Siting Act. Table 10 below summarizes the approximately 12,318 MW of proposed new natural gas-fired generation included in the 2016 Ten-Year Site Plans.

		Table 10: State of F	Natural Gas Unit	ts		
In-Service Year	Utility Name	Plant Name & Unit Number	Fuel & Unit Type	Net Capacity (MW)	Notes	
		Previou	v Units			
2016	FPL	Port Everglades Modern.	Natural Gas CC	1,237	Docket No. 110309-EI	
2017	TEC	Polk CC Conversion	Natural Gas CC	459	Docket No. 120234-EI	
2018	DEF	Citrus	Natural Gas CC	1,640	Docket No. 140110-EI	
2019	FPL	Okeechobee Energy Center	Natural Gas CC	1,622	Docket No. 150196-EI	
	P	reviously Approved Subtot	al	4,958		
2021	SEC	Unnamed CC	Natural Gas CC	649		
2023	OUC	Unspecified CC	Natural Gas CC	300		
2024	FPL	Combined Cycle Unit	Natural Gas CC	1,622		
	N	ew Units Requiring Approv	al	2,571		
2016	FPL	Ft. Myers 4A & 4B	Natural Gas CT	462		
2016	FPL	Lauderdale 6A through 6E	Natural Gas CT	1,155		
2018	GRU	South Energy Center	Natural Gas CC	8		
2018	TAL	Sub 12 DG	Natural Gas CT	18		
2021	TAL	Hopkins	Natural Gas CT	37		
2021	TAL	Purdom	Natural Gas CT	37		
2021	TEC	Future CT 1	Natural Gas CT	204		
2022	SEC	Unnamed CT 1	Natural Gas CT	201		
2023	SEC	Unnamed CT 2	Natural Gas CT	201		
2023	GPC	Combustion Turbines	Natural Gas CT	654		
2023	TEC	Future CT 2	Natural Gas CT	204		
2024	SEC	Unnamed CT 3 & CT 4	Natural Gas CT	402		
2024	DEF	Unknown P1 - P4	Natural Gas CT	812		
2025	DEF	Unknown P5	Natural Gas CT	203		
	New Ur	nits Not Requiring PPSA A	pproval	4,598		
	Tota	l Planned Natural Gas Cap	acity	12,127		
Source: 2016 Ten-Year Site Plans						

Commission's Authority over Siting

The Commission has been given exclusive jurisdiction to determine the need for new electric power plants by the Legislature, through the Electrical Power Plant Siting Act (PPSA), contained in Sections 403.501 through 403.518, F.S. Any proposed steam or solar generating unit greater than 75 MW requires a certification under the PPSA. Upon receipt of a determination of need, the electric utility would then seek approval from the Florida Department of Environmental

Protection, which addresses land use and environmental concerns. Finally, the Governor and Cabinet, sitting as the Siting Board, ultimately must approve or deny the overall certification of a proposed power plant. As shown in Table 10 above, there is approximately 2,571 MW of generation that would require certification under the PPSA in the years 2021 - 2024.

Transmission

As generation capacity increases, the transmission system must grow accordingly to maintain the capability of delivering energy to end users. The Commission has been given broad authority pursuant to Chapter 366, F.S., to require reliability within Florida's coordinated electric grid and to ensure the planning, development, and maintenance of adequate generation, transmission, and distribution facilities within the state.

The Commission has authority over certain proposed transmission lines under the Electric Transmission Line Siting Act (TLSA), contained in Sections 403.52 through 403.5365, F.S. To require certification under Florida's TLSA, a proposed transmission line must meet the following criteria: a nominal voltage rating of at least 230 kV, crossing a county line, and a length of at least 15 miles. Proposed lines in an existing corridor are also exempt from TLSA requirements. The Commission determines the reliability need and the proposed starting and end points for lines requiring TLSA certification. The proposed corridor route is subsequently determined by the Florida Department of Environmental Protection during the certification process. Much like the PPSA, the Governor and Cabinet sitting as the Siting Board ultimately must approve or deny the overall certification of a proposed line.

Table 11 below lists all proposed transmission lines in the 2016 Ten-Year Site Plans that require TLSA certification. All planned lines have already received the approval of the Commission, either independently or as part of a PPSA determination of need.

	Table 11: State of Florida - Planned Transmission Lines								
		Line	Nominal	Date	Date	In-Service			
Utility	Transmission Line	Length	Voltage	Need	TLSA	Date			
		(Miles)	(kV)	Approved	Certified				
FPL	St Johns – Pringle	25	230	05/13/2005	04/21/2006	12/01/2018			
FPL	Levee-Midway	150	500	05/28/1988	04/20/1990	06/01/2023			
FPL	Duval - Raven	45	230	02/25/2016	In Progress	12/01/2019			
TECO	Thonotosassa Wheeler	8.0	230	06/21/2007	08/07/2008	TBD			
TECO	Wheeler to Willow Oak	17.0	230	06/21/2007	08/07/2008	TBD			
Source: 2	016 Ten-Year Site Pla	ns							

Utility Perspectives

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Florida Power & Light Company (FPL)

FPL is an investor-owned utility and Florida's largest electric utility. The Utility's service territory is within the FRCC region and is primarily in south Florida and along the east coast. As an investor-owned utility, the Commission has regulatory authority over all aspects of FPL's operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds FPL's 2016 Ten-Year Site Plan suitable for planning purposes.

Load and Energy Forecasts

In 2015, FPL had approximately 4,775,382 customers and annual retail energy sales of 109,820 GWh or approximately 48.3 percent of Florida's annual retail energy sales. Figure 19 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the past 10 years, FPL's customer base has increased by 8.30 percent, while retail sales have grown by 5.94 percent. FPL exceeded its 2007 peak in 2015. FPL expects a slight decline before exceeding its 2015 peak in 2020. Since 2009, FPL has been outperforming the state average in retail energy sales growth, a trend it projects to continue into the future.



The three graphs in Figure 20 below shows FPL's seasonal peak demand and net energy for load, for the historic years 2006 through 2015 and forecast years 2016 through 2025. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. Historically, demand response was not activated during the seasonal peak demand, excluding the winters of 2010 and 2011. As an investor owned utility, FPL is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.









Fuel Diversity

Table 12 below shows FPL's actual net energy for load by fuel type for 2015, and the projected fuel mix for 2025. FPL relies primarily upon natural gas and nuclear for energy generation, making up approximately 90 percent of net energy for load.

Table 12: FPL Energy Consumption by Fuel Type							
	Net Energy for Load						
Fuel Type	201	5	2025				
	GWh	%	GWh	%			
Natural Gas	85,797	69.9%	87,435	69.9%			
Coal	5,275	4.3%	3,388	2.7%			
Nuclear	27,045	22.0%	28,871	23.1%			
Oil	462	0.4%	49	0.0%			
Renewable	157	0.1%	1,362	1.1%			
Interchange	4,730	3.9%	0	0.0%			
NUG & Other	-710	-0.6%	3,956	3.2%			
Total	122,757		125,062				

Source: 2016 Ten-Year Site Plan

Reliability Requirements

While previously only reserve margin has been discussed, Florida's utilities use multiple indices to determine the reliability of the electric supply. An additional metric is the Loss of Load Probability (LOLP), which is a probabilistic assessment of the duration of time electric customer demand will exceed electric supply, and is measured in units of days per year. FPL uses a maximum LOLP of no more than 0.1 days per year, or approximately 1 day of outage per 10 years. Between the two reliability indices, LOLP and reserve margin, the reserve margin requirement is typically the controlling factor for the addition of capacity.

Since 1999, FPL has utilized a 20 percent planning reserve margin criterion. Figure 21 below displays the forecast planning reserve margin for FPL through the planning period for both seasons, with and without the use of demand response. As shown in the figure, FPL's generation needs are controlled by its summer peak throughout the planning period.



Figure 21: FPL Reserve Margin Forecast

In addition to LOLP and the reserve margin, FPL utilizes a third reliability criterion. FPL's criterion would be to have available firm capacity 10 percent greater than the sum of customer seasonal demand, without consideration of incremental energy efficiency and all existing and incremental demand response resources. FPL refers to this as its 10 percent generation-only reserve margin. Currently, no other utility utilizes this same metric. While TECO includes a minimum supply-side contribution in its planning methodology, TECO uses a lower value of seven percent and incremental energy efficiency is included in its calculation. FPL's generation-only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20% reserve margin will be realized.

While FPL does not include incremental energy efficiency resources and cumulative demand response in its resource planning for the generation-only reserve margin criterion, the Utility would remain subject to FEECA and the conservation goals established by the Commission. FPL would continue paying rebates and other incentives to participants, which are collected from all

ratepayers through the Energy Conservation Cost Recovery Clause, but would not consider the potential capacity reductions of any future participation in energy efficiency or demand response programs during the 10-year planning period for planning purposes with this new reliability criterion only.

Energy efficiency, which includes installation of equipment designed to reduce peak demand and annual energy consumption, is considered a passive resource. While demand response must be activated by the utility, energy efficiency provides benefits consistently for the duration of the installation, reducing annual energy consumption, and if usage is coincident with system peak, peak demand. Customers do not remove building envelope improvements or newly installed equipment until the end of its service life for replacement.

As noted in the Statewide Perspective, the Commission does review the impact on reserve margin of demand response resources. At this time, FPL offers two types of demand response programs. The first type is interruptible and curtailable load programs, consisting of the Commercial/Industrial Load Control Program (CILC) and Commercial/Industrial Demand Reduction Rider (CDR) tariffs. The second type is load management programs, including the Residential On-Call and Business On-Call Programs. FPL utilizes load management programs on residential customers more often than commercial/industrial customers.

Generation Resources

FPL plans multiple unit retirements and additions during the planning period, as described in Table 13 below. The projected in-service dates of FPL's new planned nuclear units are now outside the 10-year planning period. FPL included the addition of three new natural gas-fired combined cycle units and also plans to partially replace its older gas turbine peaking capacity with new combustion turbine capacity at its Lauderdale and Fort Myers sites. On September 3, 2015, FPL filed a need determination with the Commission for the Okeechobee Unit which was granted on January 19, 2016.

As highlighted during the 2016 Ten-Year Site Plan Workshop, FPL's lower peak demand, natural gas, and CO2 price forecasts all have the impact of reducing the need for additional generation or reducing the cost-effectiveness of non-fossil fueled generation over the planning horizon. However, FPL's 2016 TYSP includes an additional 300 MW of solar generation capacity in 2020 that was not included in its 2015 TYSP. Since FPL's current planning assumptions suggest a reduction in the cost-effectiveness for adding solar generation, additional information may be needed to assess the reasonableness of such unit additions at this time.

Table 13: FPL Generation Resource Changes							
Voor	Plant Name	In:t Tune	Net Capacity (MW)	Notes			
rear	& Unit Number	Omt Type	Sum	notes			

2016	FT. Myers GT 2-7,10-12	Distillate Oil Gas Turbine	486	
2016	Lauderdale GT 1-2, 4, 6-22	Natural Gas Gas Turbine	755	
2016	Port Everglades 1 - 12	Natural Gas Gas Turbine	412	
2016	Turkey Point 1	Residual Oil Steam Turbine	396	
2017	Cedar Bay 1	250		
	Total Retir	2,299		

New Units					
2016	Babcock Solar Energy Center	Photovoltaic	75		
2016	Citrus Solar Energy Center	Photovoltaic	75		
2016	Ft. Myers 4A & 4B	Natural Gas Combustion Turbine	462		
2016	Lauderdale 6A-6E	Natural Gas Combustion Turbine	1,155		
2016	Manatee Solar Energy Center	Photovoltaic	75		
2016	Port Everglades Modern.	Natural Gas Combined Cycle	1,237	Docket No. 110309-EI	
2019	Okeechobee Energy Center	Natural Gas Combined Cycle	1,633	Docket No. 150196-EI	
2020	Unsited Solar	Photovoltaic	300		
2024	Unsited Unit	Natural Gas Combined Cycle	1,622	Requires PPSA	
Total New Units			6,633		

Net Additions	4,334	
Source: 2016 Ten-Year Site Plan		

Duke Energy Florida, LLC (DEF)

DEF is an investor-owned utility and Florida's second largest electric utility. The Utility's service territory is within the FRCC region and is primarily in central and west central Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds DEF's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, DEF had approximately 1,721,861 customers and annual retail energy sales of 38,553 GWh or approximately 17 percent of Florida's annual retail energy sales. Figure 22 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, DEF's customer base has increased by 6.26 percent, while retail sales have declined by 2.23 percent. As illustrated, retail energy sales are anticipated to exceed the historic 2006 peak by 2019, the same time as the state as a whole.



The three graphs in Figure 23 below show DEF's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the full impact of demand-side management and assume that all available demand response resources were or will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand, excluding extreme weather events. As an investor-owned utility, DEF is subject to FEECA, and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.


Fuel Diversity

Table 14 below shows DEF's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. DEF relies primarily upon natural gas and coal for energy generation, making up approximately 80 percent of net energy for load. DEF plans to substantially reduce coal usage over the planning period, but coal usage will be greater than all other energy types excluding natural gas.

Table 14: DEF Energy Consumption by Fuel Type				
	Net Energy for Load			
Fuel Type	2015		2025	
	GWh	%	GWh	%
Natural Gas	25,227	59.7%	36,828	81.4%
Coal	9,718	23.0%	5,704	12.6%
Nuclear	0	0.0%	0	0.0%
Oil	73	0.2%	2	0.0%
Renewable	1,063	2.5%	2,243	5.0%
Interchange	2,390	5.7%	62	0.1%
NUG & Other	3,809	9.0%	389	0.9%
Total	42,280		45,228	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, DEF has utilized a 20 percent planning reserve margin criterion. Figure 24 below displays the forecast planning reserve margin for DEF through the planning period for both seasons, with and without the use of demand response. As shown in the figure, DEF's generation needs are controlled by its summer peaking throughout the planning period. The Utility's summer peak percentage is projected to be slightly below its 20 percent planned reserve margin during the last three years of the planning period. The deficiency is approximately 0.5 percent which is reasonable for planning purposes.



Figure 24: DEF Reserve Margin Forecast

Generation Resources

DEF plans multiple unit retirements and additions during the planning period, as described below in Table 15. DEF's 2016 Ten-Year Site Plan includes the retirement of the coal-fired Crystal River Units 1 and 2, to be replaced by a pair of natural gas-fired combined cycle units. In addition to the units discussed above, DEF includes the retirement of seven gas-fired units at multiple power plant sites. DEF's planned additions include a combined cycle facility in 2018 in Citrus County, a purchase and proposed acquisition of the Calpine Osprey Energy Combined Cycle Unit in Auburndale and five planned Combustion Turbine Units at an undesignated site(s) with four units in 2024 and one unit in 2025.

Table 15: DEF Generation Resource Changes					
Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes	

	Retiring Units					
2016	Turner P1-2, 4	Distillate Oil Combustion Turbine	79			
2016	Suwannee River 1-3	Natural Gas Steam Turbine	128			
2016	Rio Pinar P1	Distillate Oil Combustion Turbine	12			
2018	Crystal River 1 & 2	Coal Steam Turbine	773			
2020	Avon Park P1-2	Distillate Oil Combustion Turbine	48			
2020	Higgins P1-4	Natural Gas Combustion Turbine	109			
	Total Retirements					

	New Units					
2017	Osprey CC 1	Natural Gas Combined Cycle	244	Docket No. 150043-EI		
2018	Citrus	Natural Gas Combined Cycle	1,640	Docket No. 140110-EI		
2018	Solar 5	Photovoltaic	10			
2019	Solar 6 & 7	Photovoltaic	50			
2020	Solar 8 & 9	Photovoltaic	130			
2021	Solar 10	Photovoltaic	35			
2022	Solar 11	Photovoltaic	50			
2023	Solar 12	Photovoltaic	75			
2024	Solar 13 & 14	Photovoltaic	125			
2024	Unknown P1 - P4	Natural Gas Combustion Turbine	849			
2025	Solar 15	Photovoltaic	50			
2025	Undesignated CT P5	Natural Gas Combustion Turbine	212			
	Total	l New Units	3,470			

Net Additions	2,321	
Source: 2016 Ten-Year Site Plan		

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Tampa Electric Company (TECO)

TECO is an investor-owned utility and Florida's third largest electric utility. The Utility's service territory is within the FRCC region and consists primarily of the Tampa metropolitan area. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds TECO's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, TECO had approximately 718,713 customers and annual retail energy sales of 19,006 GWh or approximately 8.4 percent of Florida's annual retail energy sales. Figure 25 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, TECO's customer base has increased by 9.9 percent, while retail sales have declined by 0.10 percent. As illustrated, retail energy sales are anticipated to exceed the historic 2007 peak by 2020, one year later than the state as a whole.



The three graphs in Figure 26 below show TECO's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak. Historically, demand response has not been activated during seasonal peak demand excluding extreme weather events.



Figure 26: TECO Demand and Energy Forecasts

As an investor-owned utility, TECO is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 16 below shows TECO's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. Based on the 2016 Ten-Year Site Plan, natural gas is used for the majority of TECO's energy generation. Natural gas accounts for approximately 50 percent of net energy for load. In the future, TECO projects that energy from coal and gas will remain approximately the same.

Table 16: TECO Energy Consumption by Fuel Type					
	Net Energy for Load				
Fuel Type	2015		2025		
	GWh	%	GWh	%	
Natural Gas	9,919	49.3%	11,321	51.9%	
Coal	8,208	40.8%	9,078	41.6%	
Nuclear	0	0.0%	0	0.0%	
Oil	0	0.0%	0	0.0%	
Renewable	341	1.7%	136	0.6%	
Interchange	438	2.2%	0	0.0%	
NUG & Other	1,200	6.0%	1,272	5.8%	
Total	20,105		21,807		

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

Since 1999, TECO has utilized a 20 percent planning reserve margin criterion. TECO also elects to maintain a minimum supply-side reserve margin of 7 percent. Figure 27 below displays the forecast planning reserve margin for TECO through the planning period for both seasons, with and without the use of demand response. As shown in the figure, TECO's generation needs are controlled by its summer peak throughout the planning period. The Utility's summer peak percentage is projected to be slightly below its 20 percent planned reserve margin in 2025. The deficiency is only 0.4 percent which is reasonable for planning purposes. TECO's 7 percent supply-side only reserve margin is not the controlling factor for any planned unit additions. However, it does provide useful information regarding the assurance that the projected 20 percent reserve margin will be realized.



Figure 27: TECO Reserve Margin Forecast

Generation Resources

TECO plans three unit additions during the planning period, as described in Table 17 below. TECO plans to convert a set of four natural gas-fired simple cycle combustion turbines at its Polk power plant to combined cycle operation. The additional capacity associated with the modernization is listed below and has already been certified through the Power Plant Siting Act. TECO also plans the addition of two natural gas-fired combustion turbine peaking units in 2020 and 2023.

Year	Plant Name	Unit Type	Net Capacity (MW)
	& Unit Number		Sum

	New Units				
2017	Big Bend Solar	Photovoltaic	18		
2017	Polk 2 CC Conversion	Natural Gas Combined Cycle	459		
2020	Future CT 1	Natural Gas Combustion Turbine	204		
2023	Future CT 2	Natural Gas Combustion Turbine	204		
	Total New Units				

	Net Additions	885
Source: 2016 Ten-Year Site Plan		

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Gulf Power Company (GPC)

GPC is an investor owned utility, and is Florida's sixth largest electric utility. It represents the smallest of the generating investor-owned utilities, and the only one inside the Southern Company electric system. As GPC plans and operates its system in conjunction with the other Southern Company utilities, not all of the energy generated by GPC is consumed within Florida. As an investor-owned utility, the Commission has regulatory authority over all aspects of operations, including rates, reliability, and safety. Pursuant to Section 186.801(2), F.S., the Commission finds GPC's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, GPC had approximately 447,557 customers and annual retail energy sales of 11,086 GWh or approximately 4.9 percent of Florida's annual retail energy sales. Figure 28 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, GPC's customer base has increased by 7.8 percent, while retail sales have declined by 3.0 percent. As illustrated, retail energy sales are anticipated to exceed the historic 2008 peak by 2025, six years later than the state as a whole.



As an investor-owned utility, GPC is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014. The three graphs in Figure 29 below shows GPC's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the full impact of demand-side management.



Fuel Diversity

Table 18 below shows GPC's actual net energy for load by fuel type as of 2015, and the projected fuel mix for 2025. GPC is an energy exporter, producing over 7.5 percent more energy than it requires for native load. While natural gas was the dominant fuel source in 2015, coal was the second most utilized fuel source. By 2025, GPC's 2016 Ten-Year Site Plan projects an increase in export to Southern Company Services that will be 8.1 percent of native load, with coal representing approximately 85 percent of system energy. GPC projects a greater percent of energy consumption from coal in 2025 than any of the other TYSP Utilities.

Table 18: GPC Energy Consumption by Fuel Type					
	Net Energy for Load				
Fuel Type	2015		2025		
	GWh	%	GWh	%	
Natural Gas	7,787	64.9%	1,828	14.5%	
Coal	4,876	40.6%	10,687	84.9%	
Nuclear	0	0.0%	0	0.0%	
Oil	1	0.0%	0	0.0%	
Renewable ⁶	235	2.0%	1,091	8.7%	
Interchange	-903	-7.5%	-1,023	-8.1%	
NUG & Other	0	0.0%	0	0.0%	
Total	11,996		12,583		

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

As previously noted, GPC is the only Ten-Year Site Plan utility outside of the FRCC region. As part of Southern Company's electric system, GPC plans to maintain a 15 percent seasonal planning reserve margin beginning in 2017. Figure 30 below displays the forecast planning reserve margin for GPC through the planning period for both seasons, including the impact of energy efficiency programs. As shown in the figure, GPC's generation needs are typically determined by its summer peak. It is anticipated that GPC would either construct additional generation or contract for purchased power to meet its planning reserve requirement in 2025.

GPC also recently filed a petition requesting that formal action is taken to recognize its ownership in Plant Scherer Unit No. 3 as being in service to retail customers. In Figure 30 below the summer reserve margin forecasts with and without Plant Scherer Unit No. 3 are shown. The winter reserve margin for Plant Scherer Unit No. 3 remained relatively unaffected. This issue will be further addressed in GPC's rate case (Docket No. 160186-EI).

⁶Gulf has entered into purchase power agreements linked to 272 MW of wind energy produced by facilities located in Oklahoma. While the energy from the facilities may not be delivered to Gulf's system, the renewable attributes for their output are retained by the utility for the benefit of Gulf's customers.



Figure 30: GPC Reserve Margin Forecast With Plant Scherer Unit No. 3

Source: 2016 Ten-Year Site Plan

Generation Resources

GPC plans multiple unit retirements and additions during the planning period, as described in Table 19 below. A coal-fired steam unit and three natural gas-fired combustion turbines will be retired during the planning period. Based on its 2016 Ten-Year Site Plan, GPC plans to add a single natural gas-fired combustion turbine in 2023, after the expiration of a purchased power agreement. In addition, GPC plans on the addition of utility-owned renewable generation from a landfill gas-fired internal combustion unit, which would provide firm capacity.

Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum
Retiring Units			
		Retiring Units	
2016	Lansing Smith 2	Retiring Units Coal Steam	19
2016 2018	Lansing Smith 2 Pea Ridge 1 - 3	Retiring Units Coal Steam Natural Gas Combustion Turbine	19

	New Units				
2023	Combustion Turbines	Natural Gas Combustion Turbine	654		
	Total New Units 6				

	Net Additions	447
Source: 2016 Ten-Year Site Plan		

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Florida Municipal Power Agency (FMPA)

FMPA is a governmental wholesale power company owned by several Florida municipal utilities throughout Florida. Collectively, FMPA is Florida's eighth largest electric utility and third largest municipal electric utility. While FMPA has 31 member systems, only those members who are participants of the All-Requirements Power Supply Project (ARP) are addressed in the Utility's Ten-Year Site Plan. FMPA is responsible for planning activities associated with ARP member systems. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds FMPA's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, FMPA had approximately 249,318 customers and annual retail energy sales of 5,617 GWh or approximately 2.5 percent of Florida's annual retail energy sales. Figure 31 below illustrates the Utility's historic and forecast number of customers and retail energy sales in terms of percentage growth from 2006. Over the last 10 years, FMPA's customer base has decreased by 13.8 percent, while retail sales have decreased by 17.8 percent. As illustrated, retail energy sales are not anticipated to exceed the historic 2007 peak during the planning period. The reduction in sales is associated with several ARP member systems modifying their contractual agreements with FMPA, such that FMPA no longer provides for the system's capacity and energy needs. Those member systems modifying agreements include the City of Vero Beach in 2010, the City of Lake Worth in 2014, and the City of Fort Meade in 2015.



The three graphs in Figure 32 below show FMPA's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. As FMPA is a wholesale power company, it does not directly engage in energy efficiency or demand response programs. ARP member systems do offer demand-side management programs, the impacts of which are included in the graphs below.



Fuel Diversity

Table 20 below shows FMPA's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. FMPA uses natural gas as its primary fuel, supplemented by coal and nuclear generation. FMPA projects an increase in purchased power and energy from coal in 2025, but approximately 86 percent of energy would still be sourced from natural gas and nuclear.

Table 20: F	MPA Ener	gy Consum	ption by Fu	el Type
		Net Energy	v for Load	
Fuel Type	20	15	202	:5
	GWh	%	GWh	%
Natural Gas	5,021	82.7%	5,500	81.7%
Coal	726	12.0%	914	13.6%
Nuclear	273	4.5%	269	4.0%
Oil	5	0.1%	0	0.0%
Renewable	42	0.7%	46	0.7%
Interchange	0	0.0%	0	0.0%
NUG & Other	6	0.1%	0	0.0%
Total	6,072		6,729	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

FMPA utilizes an 18 percent planning reserve margin criterion for summer peak demand, and a 15 percent planning reserve margin criterion for winter peak demand. Figure 33 below displays the forecast planning reserve margin for FMPA through the planning period for both seasons, with the impact of energy efficiency programs. As shown in the figure, FMPA's generation needs are controlled by its summer peak throughout the planning period.



Figure 33: FMPA Reserve Margin Forecast

Generation Resources

FMPA plans no unit additions or retirements during the planning period. However, as discussed above, several ARP member systems have elected to modify their contractual agreements with FMPA, such that FMPA no longer utilizes the member system's generation resources.

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Gainesville Regional Utilities (GRU)

GRU is a municipal utility and the smallest electric utility required to file a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and consists of the City of Gainesville and its surrounding area. GRU also provides wholesale power to the City of Alachua and Clay Electric Cooperative. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds GRU's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, GRU had approximately 94,628 customers and annual retail energy sales of 1,765 GWh or approximately 0.8 percent of Florida's annual retail energy sales. Figure 34 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, GRU's customer base has increased by 6.33 percent, while retail sales have decreased by 4.49 percent. As illustrated, retail energy sales are anticipated to exceed their historic 2007 peak in 2024, five years later than the state as a whole.



The three graphs in Figure 35 below show GRU's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. GRU engages in multiple energy efficiency programs to reduce customer peak demand and annual energy for load. The graphs in Figure 35 include the impact of these demand-side management programs.



Figure 35: GRU Demand and Energy Forecasts

Fuel Diversity

Table 21 below shows GRU's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. In 2014, coal was approximately two times natural gas in terms of contribution to net energy for load, with the remaining energy split between renewable generation and non-utility generators. But, in 2015, natural gas became GRU's primary fuel source. By 2025, GRU projects a slight increase in natural gas, approximately a 10 percent increase in coal, and approximately an 8 percent decrease in renewable energy.

	2	Net Energ	y for Load	
	2.			
Fuel Type		015	2	025
GW	h	%	GWh	%
Natural Gas	771	38.1%	921	43.4%
Coal	563	32.8%	895	42.2%
Nuclear	0	0.0%	0	0.0%
Oil	1	0.0%	0	0.0%
Renewable	374	18.5%	217	10.2%
Interchange	0	0.0%	0	0.0%
NUG & Other	215	10.6%	87	4.1%
Total 2,0	024		2,120	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

GRU utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 36 below displays the forecast planning reserve margin for GRU through the planning period for both seasons, including the impacts of demand-side management. As shown in the figure, GRU's generation needs are controlled by its summer peak throughout the planning period. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, GRU's largest single unit, Deerhaven 2, a coal-fired steam unit, represented 44.2 percent of summer net firm peak demand in 2016, almost the entirety of the Utility's reserve margin.



Figure 36: GRU Reserve Margin Forecast

Generation Resources

GRU currently plans to retire a natural gas-fired steam unit towards the end of the planning period, as described in Table 22 below. As a smaller utility, single units can have a large impact upon reserve margin. GRU does not plan to add additional generating capacity during the planning period.



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JEA

JEA, formerly known as Jacksonville Electric Authority, is Florida's largest municipal utility and fifth largest electric utility. JEA's service territory is within the FRCC region, and includes all of Duval County as well as portions of Clay and St. Johns Counties. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds JEA's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, JEA had approximately 442,249 customers and annual retail energy sales of 11,864 GWh or approximately 5.2 percent of Florida's annual retail energy sales. Figure 37 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, JEA's customer base has increased by 10.21 percent, while retail sales have declined by 5.96 percent. As illustrated, JEA exceeded its 2007 peak for retail energy sales in 2010, but does not forecast returning to that level of energy sales during the planning period.



The three graphs in Figure 38 below show JEA's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the full impact of demand-side management, and assume that all available demand response resources were or will be activated during the seasonal peak.



Figure 38: JEA Demand and Energy Forecasts

While a municipal utility, JEA is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. The Utility's 2016 Ten-Year Site Plan reflects the revised demand-side management goals established by the Commission in December 2014.

Fuel Diversity

Table 23 below shows JEA's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. In 2025, a majority JEA's net energy for load will come from coal. JEA projects the second highest percent energy consumption from coal in 2025 of the Ten-Year Site Plan utilities.

Table 23:	JEA Energ	y Consump	tion by Fu	el Type
		Net Energ	y for Load	
Fuel Type	20	15	20	25
	GWh	%	GWh	%
Natural Gas	5,209	40.5%	1,486	11.2%
Coal	5,132	39.9%	7,782	58.5%
Nuclear	0	0.0%	0	0.0%
Oil	14	0.1%	0	0.0%
Renewable ⁷	101	0.8%	126	0.9%
Interchange	935	7.3%	1,606	12.1%
NUG & Other	1,475	11.5%	2,294	17.3%
Total	12,866		13,294	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

JEA utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 39 below displays the forecast planning reserve margin for JEA through the planning period for both seasons, with and without the use of demand response. As shown in the figure, JEA's generation needs are controlled by its summer peak throughout the planning period.

⁷JEA's renewables include out of state wind resources.



Figure 39: JEA Reserve Margin Forecast

Generation Resources

JEA plans to retire one unit during the planning period, as described in Table 24 below. The Northside Unit 3, a natural gas-fired steam unit is planned for retirement in 2017 based on the Utility's Ten-Year Site Plan.

Year	Unit	Fuel & Unit Type	Net Capacity (MW)	Notes
	Name		Sum	
		Retiring Units		
2017	Northside 3	Retiring Units Natural Gas Steam	524	Reserve Storage
2017	Northside 3	Retiring Units Natural Gas Steam Retiring Units Total	524 524	Reserve Storage
2017	Northside 3	Retiring Units Natural Gas Steam Retiring Units Total	524 524	Reserve Storage

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Lakeland Electric (LAK)

LAK is a municipal utility and the state's third smallest electric utility required to file a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and consists of the City of Lakeland and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds LAK's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, LAK had approximately 125,670 customers and annual retail energy sales of 3,034 GWh or approximately 1.3 percent of Florida's annual retail energy sales. Figure 40 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, LAK's customer base has increased by 4.19 percent, while retail sales have grown by 5.06 percent. As illustrated, retail energy sales exceeded their historic 2007 peak in 2010 and 2015.



The three graphs in Figure 41 below show LAK's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. LAK offers energy efficiency programs, the impacts of which are included in the graphs below.


Fuel Diversity

Table 25 below shows LAK's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. LAK uses natural gas as its primary fuel type for energy, with coal representing about 25 percent net energy for load. While natural gas usage is anticipated to increase somewhat as a percent of net energy for load, coal is projected to decrease by 2025.

Table 25: LAK Energy Consumption by Fuel Type				
	Net Energy for Load			
Fuel Type	2	015	2025	
	GWh	%	GWh	%
Natural Gas	2,204	70.5%	2,812	83.5%
Coal	788	25.2%	624	18.5%
Nuclear	0	0.0%	0	0.0%
Oil	0	0.0%	1	0.0%
Renewable	16	0.5%	38	1.1%
Interchange	0	0.0%	0	0.0%
NUG & Other	118	3.8%	-107	-3.2%
Total	3,126		3,368	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

LAK utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 42 below displays the forecast planning reserve margin for LAK through the planning period for both seasons, including the impacts of demand-side management. As a smaller utility, the reserve margin is an imperfect measure of reliability due to the relatively large impact a single unit may have on reserve margin. For example, LAK's largest single unit, McIntosh 5, a natural gas-fired combined cycle unit, represents 30.1 percent of winter net firm peak demand in 2015, in excess of the Utility's reserve margin.



Figure 42: LAK Reserve Margin Forecast

Reserve Margin - - - LAK Planning



Generation Resources

LAK plans no unit additions or retirements during the planning period.

Orlando Utilities Commission (OUC)

OUC is a municipal utility and Florida's seventh largest electric utility and second largest municipal utility. The Utility's service territory is within the FRCC region and primarily consists of the Orlando metropolitan area. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds OUC's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, OUC had approximately 225,105 customers and annual retail energy sales of 6,536 GWh or approximately 2.9 percent of Florida's annual retail energy sales. Figure 43 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, OUC's customer base has increased by 14.57 percent, while retail sales have grown by 9.22 percent. As illustrated, retail energy sales reached a new historic peak in 2015 and are anticipated to exceed that peak in 2017.



The three graphs in Figure 44 below show OUC's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the impact of the Utility's demand side management programs. While a municipal utility, OUC is subject to FEECA and currently offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption.



Fuel Diversity

Table 26 below shows OUC's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. In 2015, OUC primarily used natural gas as fuel to meet its net energy for load at 56 percent, with coal as the second most used fuel at 37 percent. However, OUC projects an increase in the quantity of energy consumed from coal by approximately 20 percent, making coal its primary fuel source by 2025. Natural gas usage is planned to decrease by about 24 percent by 2025. Based upon this projection, OUC, as a percent of net energy for load, would be the third largest user of coal in Florida by 2025.

Table 26: OUC Energy Consumption by Fuel Type					
	Net Energy for Load				
Fuel Type	2015		2	025	
	GWh	%	GWh	%	
Natural Gas	4,578	56.4%	2,512	32.5%	
Coal	2,990	36.8%	4,287	55.4%	
Nuclear	450	5.5%	586	7.6%	
Oil	1	0.0%	0	0.0%	
Renewable	102	1.3%	347	4.5%	
Interchange	0	0.0%	0	0.0%	
NUG & Other	0	0.0%	0	0.0%	
Total	8,121		7,732		

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

OUC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 45 below displays the forecast planning reserve margin for OUC through the planning period for both seasons, including the impact of demand-side management programs. As shown in the figure, OUC's generation needs are controlled by its summer peak demand throughout the planning period.



Figure 45: OUC Reserve Margin Forecast

Generation Resources

Based upon current planning OUC is adding a combined cycle in 2021 using natural gas. The unit as shown in Table 27 below will be a 300 MW Natural Gas Unit and will require a determination of need from the Commission.

Table 27: OUC Generation Resource Changes					
Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes	
		New Units			
2021	Unknown	Natural Gas Combined Cycle	300	Requires PPSA	
	Total N	ew Units	300		
Net Additions 300					
rce: 2016 Ten-Year Site Plan					

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Seminole Electric Cooperative (SEC)

SEC is a generation and transmission rural electric cooperative that serves its member cooperatives, and is collectively Florida's fourth largest utility. SEC's generation and member cooperatives are within the FRCC region, with member cooperatives located in central and north Florida. As a rural electric cooperative, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds SEC's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, SEC had approximately 751,848 customers and annual retail energy sales of 13,374 GWh or approximately 5.9 percent of Florida's annual retail energy sales. Figure 46 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, SEC's customer base has decreased by 13.59 percent, and retail sales have decreased 16.12 percent. As illustrated, retail energy sales are not anticipated to exceed their historic 2007 peak during this planning period. The decline shown in 2014 is associated with one member cooperative, Lee County Electric Cooperative, electing to end its membership with SEC.



The three graphs in Figure 47 below show SEC's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. As SEC is a generation and transmission company, it does not directly engage in energy efficiency or demand response programs. Member cooperatives do offer demand-side management programs, the impacts of which are included in Figure 47.



Figure 47: SEC Demand and Energy Forecasts

Fuel Diversity

Table 28 below shows SEC's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. In 2015, SEC uses a combination of coal and natural gas to meet its member cooperatives' net energy for load, with coal use slightly higher than natural gas. By 2025, SEC projects this to reverse, with natural gas usage somewhat higher than coal.

Table 28: SEC Energy Consumption by Fuel Type				
	Net Energy for Load			
Fuel Type	2015		2025	
	GWh	%	GWh	%
Natural Gas	5,333	37.8%	8,625	53.2%
Coal	7,803	55.3%	7,363	45.4%
Nuclear	0	0.0%	0	0.0%
Oil	36	0.3%	50	0.3%
Renewable	932	6.6%	186	1.1%
Interchange	0	0.0%	0	0.0%
NUG & Other	0	0.0%	0	0.0%
Total	14,104		16,224	

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

SEC utilizes a 15 percent planning reserve margin criterion for seasonal peak demand. Figure 48 below displays the forecast planning reserve margin for SEC through the planning period for both seasons, with and without the use of demand response. Member cooperatives allow SEC to coordinate demand response resources to maintain reliability. As shown in the figure, SEC's generation needs are determined by winter peak demand more often than summer peak demand during the planning period.



Figure 48: SEC Reserve Margin Forecast

Source: 2016 Ten-Year Site Plan

Generation Resources

SEC plans the addition of several generating units during the planning period, as described in Table 29 below. All unsited natural gas-fired units, SEC plans the addition of a total of four combustion turbines and a single combined cycle unit over the planning period.

Table 29: SEC Generation Resource Changes						
	Year	Plant Name & Unit Number	Unit Type	Net Capacity (MW) Sum	Notes	

	New Units					
2021	Unnamed CC	Natural Gas Combined Cycle	649	Requires PPSA		
2021	Unnamed CT 1	Natural Gas Combustion Turbine	201			
2022	Unnamed CT 2	Natural Gas Combustion Turbine	201			
2024	Unnamed CT 3 & 4	Natural Gas Combustion Turbine	201			
	Total	1,252				
Jurgas 7	urger 2016 Ten Veer Site Dien					

Source: 2016 Ten-Year Site Plan

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City of Tallahassee Utilities (TAL)

TAL is a municipal utility and the second smallest electric utility which files a Ten-Year Site Plan. The Utility's service territory is within the FRCC region and primarily consists of the City of Tallahassee and surrounding areas. As a municipal utility, the Commission's regulatory authority is limited to safety, rate structure, territorial boundaries, bulk power supply, operations, and planning. Pursuant to Section 186.801(2), F.S., the Commission finds TAL's 2016 Ten-Year Site Plan suitable for planning purposes.

Load & Energy Forecasts

In 2015, TAL had approximately 117,827 customers and annual retail energy sales of 2,655 GWh or approximately 1.2 percent of Florida's annual retail energy sales. Figure 49 below illustrates the Utility's historic and forecast number of customers and retail energy sales, in terms of percentage growth from 2006. Over the last 10 years, TAL's customer base has increased by 6.58 percent, while retail sales have declined by 2.17 percent. As illustrated, retail energy sales are not anticipated to exceed their historic 2007 peak until 2018.



The three graphs in Figure 50 below show TAL's seasonal peak demand and net energy for load for the historic years of 2006 through 2015 and forecast years 2016 through 2025. These graphs include the impact of demand-side management, and for future years assume that all available demand response resources will be activated during the seasonal peak. TAL offers energy efficiency and demand response programs to customers to reduce peak demand and annual energy consumption. Currently TAL only offers demand response programs targeting appliances that contribute to summer peak, and therefore have no effect upon winter peak.



Figure 50: TAL Demand and Energy Forecasts

Fuel Diversity

Table 30 below shows TAL's actual net energy for load by fuel type as of 2015 and the projected fuel mix for 2025. TAL relies almost exclusively on natural gas for its generation, excluding some purchases from other utilities and qualifying facilities and the use of oil as a backup fuel. Natural gas is anticipated to remain the primary fuel source on the system.

Table 30: TAL Energy Consumption by Fuel Type					
	Net Energy for Load				
Fuel Type	2015		2025		
	GWh	%	GWh	%	
Natural Gas	2,704	97.4%	3,001	98.9%	
Coal	0	0.0%	0	0.0%	
Nuclear	0	0.0%	0	0.0%	
Oil	0	0.0%	0	0.0%	
Renewable	16	0.6%	53	1.7%	
Interchange	0	0.0%	0	0.0%	
NUG & Other	55	2.0%	-20	-0.7%	
Total	2,775		3,035		

Source: 2016 Ten-Year Site Plan and Data Responses

Reliability Requirements

TAL utilizes a 17 percent planning reserve margin criterion for seasonal peak demand. Figure 51 below displays the forecast planning reserve margin for TAL through the planning period for both seasons, with and without the use of demand response. As discussed above, TAL only offers demand response programs applicable to the summer peak. As shown in the figure, TAL's generation needs are controlled by its summer peak throughout the planning period.



Figure 51: TAL Reserve Margin Forecast

Generation Resources

TAL plans multiple unit retirements and a single addition during the planning period, as described in Table 31 below. Several older combustion turbines at two plant sites and a single steam unit, all natural gas-fired, are anticipated to be retired during the planning period. Based upon its current planning, TAL intends to add a new natural gas-fired combustion turbine in 2018.

Table 31: TAL Generation Resource Changes				
Year	Plant Name	Unit Type	Net Capacity (MW)	
	& Unit Number		Sum	

	Retiring Units				
2017	Hopkins CT-1	Natural Gas Gas Turbine	12		
2017	Purdom CT-1 & CT-2	Natural Gas Gas Turbine	20		
2018	Hopkins CT-2	Natural Gas Gas Turbine	24		
2021	Hopkins 1	Natural Gas Steam Turbine	76		
	Total R	132			

New Units			
2018	Substation 12 IC 1-2	Natural Gas Internal Combustion	9
Total New Units			9

	Net Additions	(123)
Source: 20	16 Ten-Year Site Plan	

APPENDIX A

REVIEW OF THE <u>2016 TEN-YEAR SITE PLANS</u> OF FLORIDA'S ELECTRIC UTILITIES



NOVEMBER 2016

State Agencies

- Fish and Wildlife Conservation Commission- General
- Fish and Wildlife Conservation Commission- Gulf
- Department of Environmental Protection

Regional Planning Councils

• Treasure Coast Regional Planning Council

Water Management Districts

- Southwest Florida Water Management District
- St. Johns Water Management District

Local Governments

• Charlotte County

Environmental Groups

- Southern Alliance for Clean Energy
- Sierra Club



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MyFWC.com

June 21, 2016

Moniaishi Mtenga Division of Engineering Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399-0850 <u>mmtenga@psc.state.fl.us</u>

RE: 2016 Ten-Year Power Plant Site Plans

Dear Mr. Mtenga:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the 2016 Ten-Year Power Plant Site Plans submitted to the Public Service Commission (PSC). We will be providing comments on the Gulf Power Company (GULF) Ten-Year Site Plan in a subsequent letter. However, we are submitting this letter to notify you that we have reviewed the following plans and have no comments regarding fish and wildlife resources:

Gainesville Regional Utilities (GRU) Orlando Utilities Commission (OUC) City of Tallahassee Utilities (TAL) Jacksonville Energy Authority (JEA) Florida Municipal Power Agency (FMPA) Florida Power and Light Company (FPL) Seminole Electric Cooperative (SEC) Lakeland Electric (LAK) Tampa Electric Company (TECO) Duke Energy Florida (DEF)

We appreciate the opportunity to review the Ten-Year Site Plans, as provided by the PSC. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or by email at <u>FWCConservationPlanningServices@MyFWC.com</u>. If you have specific technical questions, please contact Jason Hight either by phone at (850) 413-6966 or by email at <u>Jason.Hight@MyFWC.com</u>.

Sincerely,

Jernifu D. Soft

Jennifer D. Goff Land Use Planning Program Administrator Office of Conservation Planning Services

jdg/jh ENV 2-11-3 2016 Ten-Year Site Plans_30912, 30917, 30910, 30916, 30921, 30925, 30911, 30914, 30923, 30924_062416



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July 6, 2016

Moniaishi Mtenga Division of Engineering Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399-0850 <u>mmtenga@psc.state.fl.us</u>

RE: Gulf Power 2016 10-Year Site Plan, Multi-County

Dear Mr. Mtenga:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the Gulf Power 2016 10-Year Site Plan and provides the following comments and recommendations.

Project Description

Section 186.801, Florida Statutes, requires electric generating facilities to submit a tenyear site plan to the Florida Public Service Commission. Gulf Power owns and operates five plants in Northwest Florida: Plant Crist (Escambia County); Plant Lansing Smith (Bay County); Plant Scholz (Jackson County); Pea Ridge (Santa Rosa County); and Perdido (Escambia County). Gulf Power has continued to evaluate the construction of generating facilities or the acquisition of equivalent capacity resources in coordination with other Southern Electric System (SES) operating companies. Gulf Power indicates that it has satisfied its need for firm capacity through the May 2023 time period. Any new facility construction is deferred during the 2016-2025 planning cycle. Gulf Power will consider future additional capacity at its existing sites at the Plant Crist, Plant Lansing Smith, Plant Scholz, or on the identified Gulf Power sites at the Shoal River property in Walton County, Caryville property in Holmes and Washington counties, or the North Escambia County property.

Potentially Affected Fish and Wildlife Resources

FWC staff previously provided comments to Gulf Power on the potentially affected resources at the proposed facility expansion sites during the 2010 and 2012 Plan Reviews, with the exception of the proposed North Escambia County Site (see enclosure). Since that time, the listing status of several species has changed which affects the discussion of unique or significant environmental features that are discussed under each site description in the Ten-Year Site Plan. We are providing the following information as technical assistance at the request of Gulf Power staff so that they may update these descriptions.

Moniaishi Mtenga Page 2 July 6, 2016

<u>Plant Crist</u> (Escambia County) is located adjacent to the Escambia River. FWC GIS analysis found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Critical Habitat for the:
 - Gulf sturgeon (Acipenser oxyrinchus desotoi, Federally Threatened (FT)
- Potential habitat for the:
 - Harlequin darter (*Etheostoma histrio*, State Species of Special Concern [SSC])

<u>Plant Scholz</u> (Jackson County) is located adjacent to the Apalachicola River. FWC GIS analysis found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Critical Habitat for the:
 - o Gulf sturgeon (Acipenser oxyrinchus desotoi, FT)
 - o Purple bankclimber (Elliptoides sloatianus, FT)
 - o Fat three-ridge (Amblema neislerii, Federally Endangered [FE])
- Potential habitat for the:
 - Barbour's map turtle (Graptemys barbouri, SSC)

The undeveloped Shoal River Site (Walton County) is located on the Shoal River approximately 3 miles northwest of Mossy Head, Florida. The property is predominantly in pine plantation. FWC GIS analysis found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Consultation Area for the:
 - Red-cockaded woodpecker (Picoides borealis, FE)
- U.S. Fish and Wildlife Service Critical Habitat for the:
 - o Southern sandshell mussel (Hamiota australis, FT)
 - o Choctaw bean (Villosa choctawensis, FE)
 - o Narrow pigtoe (Fusconaia escambia, FT)
 - o Fuzzy pigtoe (Pleurobema strodeanum, FT)
- Potential habitat for the:
 - o Gopher tortoise (Gopherus polyphemus, State Threatened [ST])
 - Blackmouth shiner (*Notropis melanostomus*, ST)
 - o Bluenose shiner (Pteronotropis welaka, SSC)
 - o Alligator snapping turtle (Macrochelys temminckii, SSC)
 - o Eastern indigo snake (Drymarchon couperi, FT)
 - o Pine barrens treefrog (Hyla andersonii, SSC)
 - o Florida black bear (Ursus americanus floridanus)

The undeveloped Caryville Site (Holmes and Washington counties) is approximately 1.5 miles northeast of Caryville, Florida, and adjacent to the Choctawhatchee River. The property is predominantly in agriculture and pine plantation. FWC staff conducted a GIS analysis and found that this site is located near, within, or adjacent to:

- U.S. Fish and Wildlife Service Critical Habitat for the:
 - o Gulf sturgeon (Acipenser oxyrinchus desotoi, FT)
 - o Southern sandshell mussel (Hamiota australis, FT)
 - Choctaw bean (Villosa choctawensis, FE)

Moniaishi Mtenga Page 3 July 6, 2016

- Southern kidneyshell (Ptychobranchus jonesi, FE)
- Tapered pigtoe (Fusconaia burki, FT)
- o Fuzzy pigtoe (Pleurobema strodeanum, FT)
- Potential habitat for the:
 - Gopher tortoise (Gopherus polyphemus, ST)
 - o Barbour's map turtle (Graptemys barbouri, SSC)
 - Bluenose shiner (Pteronotropis welaka, SSC)
 - o Eastern indigo snake (Drymarchon couperi, FT)
 - Pine barrens treefrog (Hyla andersonii, SSC)
 - Alligator snapping turtle (Macrochelys temminckii, SSC)
 - o Florida black bear (Ursus americanus floridanus)

The undeveloped North Escambia Property Site (Escambia County) is approximately 5 miles southwest of Century, Florida near County Road 4 and U.S. Highway 29. The site contains part of the Mitchell Creek drainage basin. FWC GIS analysis found that this site is located near, within, or adjacent to:

- Potential habitat for the:
 - o Gopher tortoise (Gopherus polyphemus, State Threatened [ST])
 - Harlequin darter (*Etheostoma histrio*, SSC)
 - o Sherman's fox squirrel (Sciurus niger shermani, SSC)

With the addition of the information provided above, FWC finds that Gulf Power's 2016 10-year Site Plan 2016-2025 document is suitable for planning purposes and the plan proposes no significant impacts to fish and wildlife resources as written. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at <u>FWCConservationPlanningServices@MyFWC.com</u>. If you have specific technical questions regarding the content of this letter, please contact Theodore Hoehn at (850) 488-8792 or by email at <u>ted.hoehn@MyFWC.com</u>.

Sincerely,

Junifu D. Soft

Jennifer D. Goff Land Use Planning Program Administrator Office of Conservation Planning Services

jdg/th ENV 2-11-4/3 Gulf Power Company 2016 Ten-Year Site Plan_30922_070616 Enclosure

cc: Robert McGee, Jr., Gulf Power, <u>RLMMCGEE@southernco.com</u>



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June 7, 2012

Mr. Phillip Ellis Division of Regulatory Analysis Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399-0850 pellis@psc.statea.fl.us

RE: Gulf Power 2012 10-Year Site Plan, Multi-County

Dear Mr. Ellis:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the Gulf Power 2012 10-Year Site Plan and provides the following comments and recommendations for your consideration.

Project Description

Section 186.801, Florida Statutes requires electric generating facilities to submit a tenyear site plan to the Florida Public Service Commission. Gulf Power owns and operates five plants in Northwest Florida: Plant Crist (Escambia County); Plant Lansing Smith (Bay County); Plant Sholtz (Jackson County); Pea Ridge (Santa Rosa County); and Perdido (Escambia County). Gulf Power has continued to evaluate the construction of generating facilities or the acquisition of equivalent capacity resources in coordination with other Southern Electric System (SES) operating companies. Gulf Power indicates that it has satisfied its need for firm capacity through the May 2023 time period. Any new facility construction is deferred during the 2012-2021 planning cycle. Gulf Power will consider additional capacity at its existing sites at the Plant Crist, Plant Lansing Smith, Plant Scholtz, or at the identified sites on the Shoal River property in Walton County or the Caryville property in Holmes and Washington Counties.

Potentially Affected Resources

Plant Crist (Escambia County) is located adjacent to the Escambia River, which has been designated as Critical Habitat for the Gulf Sturgeon [*Acipenser oxyrinchus desotoi* – Federal Threatened (FT)]. The undeveloped portion of the site includes mixed hardwoods/pines and mixed scrub.

Plant Lansing Smith (Bay County) is located along North Bay of the St. Andrews Bay system. The undeveloped portion of the site is predominantly pine plantation with some wetland areas. The site is adjacent to areas identified for conservation under the Bay County Sector Plan.

Plant Scholtz (Jackson County) is located adjacent to the Apalachicola River. The site consists of a mixture of pine and hardwood forests. Plant Scholtz is adjacent to the Apalachicola River, which has designated critical habitat for the Gulf Sturgeon

[Acipenser oxyrinchus desotoi (FT)], and critical habitat for the purple bankclimber [Elliptoides sloatianus (FT)] and fat three-ridge [Amblema neislerii - Federal Endangered (FE)].

The undeveloped Shoal River Site (Walton County) is located on the Shoal River approximately 3 miles northwest of Mossy Head, Florida. The property is predominantly in pine plantation. The site falls within a federally designated red-cockaded woodpecker consultation area; and contains primary and secondary habitat for the Florida black bear [*Ursus americanus floridanus* – State Threatened (ST)]. This site is also within close proximity to known occurrences of southern sandshell mussel (*Hamiota australis* – Federal, Candidate Endangered), blackmouth shiner [*Notropis melanostomus* – State Endangered (SE)], bluenose shiner [*Pteronotropis welaka* – State Species of Special Concern (SSC)], Eastern indigo snake [*Drymarchon couperi* – (FT)], alligator snapping turtle [*Macrochelys temminckii* (State SSC)], gopher tortoise [*Gopherus polyphemus* – (ST)], and pine barrens treefrog [*Hyla andersonii* (State SSC)].

The undeveloped Caryville Site (Holmes/Washington County) is approximately 1.5 miles northeast of Caryville, Florida. The property is predominantly in agriculture and pine plantation. The site may contain gopher tortoise [Gopherus polyphemus (ST)], pine barrens treefrog [Hyla andersonii (State SSC)], and the Eastern indigo snake [Drymarchon couperi (FT)]. The site is also within close proximity to the Choctawhatchee River, which contains critical habitat for the Gulf Sturgeon [Acipenser oxyrinchus desotoi (FT)] and known occurrences of Barbour's Map Turtle [Graptemys barbouri (State SSC)], Fuzzy Pigtoe (Pleurobema strodeanum – Federal, Candidate Endangered), and bluenose shiner [Pteronotropis welaka (State SSC)].

FWC appreciates the opportunity to review Gulf Power's 2012 10-year Site Plan 2012-2021 document and extends an offer to assist Gulf Power in further identifying fish and wildlife resources within their planning area. Based on our review, we have determined that there are no development plans proposed in this Gulf Power Planning document that appear to pose significant fish and wildlife resource issues or potential conflicts for this planning period. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at

<u>FWCConservationPlanningServices@MyFWC.com</u>. If you have specific technical questions regarding the content of this letter, please contact Theodore Hoehn at 850-488-8792 or by email at <u>ted.hoehn@myfwc.com</u>.

Sincerely,

Bongo Sahan

Scott Sanders, Director Office of Conservation Planning Services

ss/bg/th ENV 2-11-4/3 Gulf Power Company 2012 10-year Site Plan_16170_060712 cc: Susan Ritenour, Gulf Power, <u>SDRITENO@southernco.com</u> Good afternoon,

The Department of Environmental Protection's Siting Coordination Office has reviewed the 2016 Ten-Year Site Plans for Florida's Electric Utilities and found the documents to be adequate for planning purposes. Thank you for the opportunity to review and comment on the plans.

Bobby Bull, P.E. Siting Coordination Office 2600 Blair Stone Road MS 5500 Tallahassee, FL 32399 <u>Robert.Bull@dep.state.fl.us</u> 850/717-9111

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TREASURE COAST REGIONAL PLANNING COUNCIL

Report on the

Florida Power & Light Company Ten Year Power Plant Site Plan 2016-2025

July 15, 2016

Introduction

Each year every electric utility in the State of Florida produces a ten year site plan that includes an estimate of future electric power generating needs, a projection of how those needs will be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The Florida Public Service Commission (FPSC) has requested that Council review the most recent ten year site plan prepared by Florida Power & Light Company (FPL). The purpose of this report is to summarize FPL's plans for future power generation and provide comments for transmittal to the FPSC.

Summary of the Plan

The plan indicates that total summer peak demand is expected to grow by 9.9 percent from 24,170 megawatts (MW) in 2016 to 26,572 MW in 2025. During the same period, FPL is expecting to reduce electrical use through demand side management programs, which include a number of conservation, energy efficiency, and load management initiatives. FPL's demand side management programs are expected to grow by 26.7 percent from 1,842 MW in 2016 to 2,334 MW in 2025. After FPL's demand side management efforts are factored in, FPL will still require additional capacity from conventional power plants to meet future electrical demand (Exhibit 1). FPL is proposing to add a total of about 2,989 MW of summer capacity to its system from 2016 to 2025. FPL plans to obtain additional electricity through: 1) power purchases from qualifying facilities, utilities, and other entities; 2) upgrades to existing facilities; 3) modernization of existing FPL facilities; and 4) construction of new generating units. Major additions of new generating capacity are as follows:

- 2016 place in service the Port Everglades Next Generation Clean Energy Center (1,237 MW) in the City of Hollywood;
- 2017 place in service five new combustion turbines to replace gas turbines at the Lauderdale site (1,155 MW) in Broward County;
- 2019 place in service the Okeechobee Next Generation Clean Energy Center (1,633 MW) in Okeechobee County; and
- 2024 place in service a new combined cycle power plant (1,317 MW) (not sited).

Based on the projection of future resource needs, FPL has identified the following seven preferred sites for future power generating facilities:

- 1. Babcock Ranch Solar Energy Center, Charlotte County
- 2. Citrus Solar Energy Center, DeSoto County

- 3. Manatee Solar Energy Center, Manatee County
- 4. Lauderdale Plant Peaking Facilities, Broward County
- 5. Fort Myers Plant Peaking Facilities, Lee County
- 6. Okeechobee Site, Okeechobee County
- 7. Turkey Point Plant, Miami-Dade County

Also, FPL has identified six potential sites for new or expanded power generating facilities. The identification of potential sites does not represent a commitment by FPL to construct new power generating facilities at these sites. The potential sites include:

- 1. Alachua County
- 2. Hendry County
- 3. Martin County
- 4. Miami-Dade County
- 5. Putnam County
- 6. Volusia County

The ten year site plan describes five factors that have impacted or could impact FPL's resource plan. These factors include:

- 1. Maintaining/enhancing fuel diversity in the FPL system.
- 2. Maintaining a balance between load and generating capacity in southeastern Florida, particularly in Miami-Dade and Broward counties.
- 3. Maintaining an appropriate balance of demand side management and supply resources to achieve system reliability.
- 4. The impact of federal and state energy efficiency codes and standards on FPL's forecasted future demand and energy requirements.
- 5. The increasing cost competitiveness of utility-scale photovoltaic (PV) facilities due to the continued decline of the cost of PV modules and the recent extension of federal tax credits.

Evaluation

One of the main purposes of preparing the ten year site plan is to disclose the general location of proposed power plant sites. The FPL ten year site plan identifies no preferred sites and one potential site for future power generating facilities in the Treasure Coast Region (Exhibit 2). The only potential site identified in the Treasure Coast Region is Martin County. The plan indicates FPL is currently evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

One preferred site, the Okeechobee site is located in northeastern Okeechobee County directly adjacent to Indian River County. Natural gas is expected to be supplied by an existing pipeline as well as a future pipeline. The FPSC issued a determination of need order approving this unit on January 19, 2016. The Florida Department of Environmental Protection has recently issued a final order approving certification of this facility. Indian River County was a party to the site certification proceeding and FPL coordinated with Indian River County regarding possible

impacts to the county. The conditions of certification for the new Okeechobee Next Generation Clean Energy Center address impacts to Indian River County related to traffic, traffic impact fees, and emergency services.

The ten year site plan indicates that fossil fuels will be the primary source of energy used to generate electricity by FPL during the next 10 years (Exhibit 3). The plan indicates fossil fuels will account for 72.6 percent (3.3 percent from coal, 1.5 percent from oil, and 67.8 percent from natural gas) of FPL's electric generation in 2016. The plan predicts fossil fuels will account for 72.6 percent (2.7 percent from coal, 0 percent from oil, and 69.9 percent from natural gas) of FPL's electric generation in 2025. During the same period, nuclear sources are predicted to change from 23.9 percent in 2016 to 23.1 percent in 2025. Solar sources are predicted to increase from 0.1 percent in 2016 to 1.0 percent in 2025.

Renewable Energy

The 10 year site plan indicates FPL is increasing its efforts to implement cost-effective renewable energy. The factors driving these efforts are: 1) the price of PV modules has declined in recent years; 2) FPL has developed a methodology with which it can assign a firm capacity benefit for meeting FPL's summer peak load to PV; and 3) FPL has concluded from its implementation and analyses of utility-scale PV and PV demand side pilot programs that utility-scale PV applications are the most economical way to utilize solar energy. FPL's efforts to increase use cost-effective renewable energy include the use of utility-scale PV facilities and distributed generation PV pilot programs, which are described below.

Utility-scale PV Facilities. FPL is planning to add three new PV facilities by the end of 2016. These are the Babcock Ranch Solar Energy Center in Charlotte County, Citrus Solar Energy Center in DeSoto County, and Manatee Solar Energy Center in Manatee County. Each of the PV facilities will be approximately 74.5 MW. These new facilities will be in addition to the existing Martin Next Generation Solar Energy Center (75 MW) in Martin County, the DeSoto Next Generation Solar Energy Center (25 MW) in DeSoto County, and the Space Coast Next Generation Solar Energy Center (10 MW) in Brevard County. The new facilities will increase FPL's solar generation capacity from its current 110 MW to approximately 333 MW. Also, FPL is projecting the addition of another approximately 300 MW of PV that will be added by the year 2021. This will result in an approximately 633 MW by 2021. A final determination of the siting of this 300 MW of additional PV has not yet been made.

Distributed Generation PV Pilot Programs. FPL has three types of distributed generation (DG) PV programs. First is the *Community-based Solar Partnership Pilot Program*, which is a voluntary solar pilot program to provide customers with an additional and flexible opportunity to support development of solar power in Florida. This pilot program will provide all customers the opportunity to support the use of solar energy at a community scale and is designed for customers who do not wish, or are not able, to place solar equipment on their roof. Customers can participate in the program through voluntary contributions of \$9/month. The voluntary contribution is required, because the cost per MW to construct this type of distributed generation scale facility is approximately double the cost of utility scale facilities. Also, the operation and

maintenance costs of these facilities are expected to be three times as much as for utility-scale PV systems. The first 175 kW of DG PV projects under this pilot program are located in the City of West Palm Beach and in Broward County. Additional PV facilities under this program will be built when the projected voluntary contributions are sufficient to cover on-going program costs without increasing electric rates for all customers. The locations of additional PV facilities have not yet been determined.

The second type of DG PV program is the *Commercial and Industrial Partnership Pilot Program.* This pilot program will be conducted in partnership with interested commercial and industrial customers over about a five year period. Limited investments will be made in PV facilities located at customer sites in selected geographic areas of FPL's service territory. The primary objective of this program is to examine the effect of high penetration of DG PV on FPL's distribution system and to determine how best to address any problems that may be identified. FPL will site approximately 4 MW of PV facilities on circuits that experience specific loading conditions to better study impacts. PV installations at Daytona International Speedway, Daytona Kennel Club and Poker Room, and Florida International University's Engineering Center campus in West Miami-Dade County have been selected based on their interconnection with targeted circuits.

The third type of DG PV program is the *Battery Storage Pilot Program*. The purpose of this pilot program is to demonstrate and test a wide variety of battery storage grid applications. In addition, the pilot program is designed to help FPL learn how to integrate battery storage into the grid. Under this pilot program, FPL is installing a 1.5 MW battery storage system in Miami-Dade County. In addition, a battery storage system of 1.5 MW is also being installed in Monroe County for backup power and voltage support. Several smaller kilowatt-scale systems are also being installed at other locations to study distributed storage reliability applications.

Conclusion

Council is encouraged that FPL will have tripled its solar capacity by building three more 74.5 MW solar energy centers by the end of 2016. The amount of electricity generated by FPL's six solar plants will be the equivalent of 65,000 residential rooftop solar installations. FPL is preparing to build even more large scale solar projects in the next 5 years, while at the same time constructing and operating highly efficient natural gas plants that have decreased dependence on foreign oil and saved energy costs. This has resulted in FPL having the lowest rates of all electric utilities in the State of Florida and among the lowest rates in the nation.

Council recommends that FPL continue to make progress toward adopting a more balanced portfolio of fuels that includes a significant component of renewable energy sources. This is important to reduce vulnerability to fuel price increases and supply interruptions. Council continues to encourage the Florida Legislature to adopt a Renewable Portfolio Standard in order to provide a mechanism to expand the use of renewable energy in Florida.

Council supports FPL's existing and proposed solar projects and encourages FPL to develop additional projects based on renewable resources. FPL should consider developing other programs to install, own, and operate PV units on the rooftops of private and public buildings.

The shift to rooftop PV systems distributed throughout the area of demand could reduce reliance on large transmission lines and reduce costs associated with owning property; purchasing fuel; and permitting, constructing, and maintaining a power plant. Another advantage of this strategy is that PV systems do not require water for cooling. The incentive for owners of buildings to participate in this strategy is they could be offered a reduced rate for purchasing electricity. Also, FPL should consider expanding solar rebate programs for customers who install PV and solar water heating systems on their homes and businesses. These rebates should be coordinated with other programs, such as the Solar and Energy Loan Fund (SELF) and Property-Assessed Clean Energy (PACE) programs, to provide participants in these programs the option of receiving a rebate. SELF is a low interest rate loan program that provides financing for clean energy solutions. PACE programs allow property owners to finance energy retrofits by placing an additional tax assessment on the property in which the investment is made.

Council urges FPL and the State of Florida to continue developing new programs to: 1) reduce the reliance on fossil fuels as future energy sources; 2) increase conservation activities to offset the need to construct new power plants; and 3) increase the reliance on renewable energy sources to produce electricity. The complete costs of burning fossil fuels, such as the costs to prevent environmental pollution and costs to the health of the citizens, need to be considered in evaluating these systems. State legislators should amend the regulatory framework to provide financial incentives for the power providers and the customers to increase conservation measures and to rely to a greater extent on renewable energy sources. Also, the state should reconsider the currently used test for energy efficiency and choose a test that will maximize the potential for energy efficiency and renewable energy sources. The phasing in of PV and other locally available energy sources will help Florida achieve a sustainable future.

Attachments
Exhibit 1

Yoar*	Projected Capacity & Firm Purchase Power Changes	Summer MW	Date	Summer Reserve Margin *
2016	Fort Myers 2	8	January 2016	
	Fort Myers 3A	25	June 2016	
	Martin 4	15	April 2016	
	Martin 8	(5)	March 2016	
	Port Everolades Next Generation Clean Energy Center	1.237	April 2016	
261	Total of MW changes to Summer firm capacity:	1,280	MICHARMINER	22.0%
2017	Babcock Solar Energy Center (Charlotte) ***	38	December 2016	and the second second
	Citrus Solar Energy Center (DeSoto) ***	38	December 2016	
	Manatee Solar Energy Center ***	38	December 2016	
	Unspecified Short-Term Purchase	53	April 2016	
	Turkey Point Unit 1 synchronous condenser	(396)	December 2016	
	Port Everalades GTs	(412)	October 2016	
	Codar Bay	(250)	January 2017	
	Lauderdale GT 1-12	(343)	October 2016	
	Lauderdale GT 13-22	(412)	October 2016	
	Lauderdale GTs - 5 CT	1 155	December 2016	
	Fort Myers - 2 CT	402	December 2016	-
	Fort Myers 30	304	December 2010	
	Fort Myers Job	400	July 2010	
	For Myers G1 1- 12	(460)	June 2016	
	Madun a	21	August 2010	
	Martin 4	13	April 2016	
	Martin 8	(0)	March 2016	
1000-000	Manatee 3	(11)	May 2017	00.01/
2018	Linesected Shed Term Durchase	(465)	And 2010	20.0%
2010	Conspectited Short-Term Purchase	329	April 2016	
	Sentord 4	122	September 2017	
	Seniord 5 Turkey Delet Numbers Link #F	(1)	July 2017	
No. 1244	Turkey Point Nuclear Unit #5	(15)	January 2018	00.01/
2010	Turkey Delet Nuclear Link #2	307	Eall 0048	20.0%
2019	Turkey Point Nuclear Unit #3	20	Fail 2018	
	Turkey Point Nuclear Unit #4	20	Spring 2019	
1000	Okeechobee Next Generation Clean Energy Center	1,633	June 2019	
0000	Total of MW changes to Summer firm capacity:	1,873	THE REPORT OF A DECISION	24.6%
2020	SJRPP suspension of energy	(382)	4th Qtr 2019	
	Unsited Solar (PV)	156	June 2020	-
0004	Total of MW changes to Summer firm capacity:	156		22.2%
2021	Eco-Gen PPA tim capacity	180	January 2021	
	Cape Next Generation Clean Energy Center	88	Spring 2021	
DUCOV	Total of MW changes to Summer firm capacity:	268	THE LEVEL OF A DECKER	23.0%
2022	Riviera Beach Next Generation Clean Energy Center	86	Spring 2022	
	Total of MW changes to Summer firm capacity:	86	WHAT IS CONVERSION OF	22.5%
2023	848			
NI State	Total of MW changes to Summer firm capacity:	0	Real The State State	21.2%
2024	Unsited CC	1,622	June 2024	
1 STA	Total of MW changes to Summer firm capacity:	1,622		26.5%
2025	***			
PAC 107 PAL 107				

Table ES-1: Projected Capacity & Firm Purchase Power Changes

 Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations.

** Winter Reserve Margins are typically higher than Summer Reserve Margin. Winter Reserve Margin are shown on Schedule 7.2 in Chapter III.

*** MW values shown for the PV facilities represent the firm capacity assumptions for the PV facilities.

Florida Power & Light Company



Exhibit 3

				-		Energy So	urces % by Fu	el Type		i.				
		1	Actual						Forecast	pa				
	Energy Source	Units	2014	2015	2916	2012	2015	2019	2020	2021	2022	2021	2024	2025
0	Annuai Energy Interchanga 2	×	42	3.9	1	0.7	979	6.8	90	0.0	0.0	00 .	90	0.0
R	Nuclear	*	23.1	22.0	23.9	23.5	23.6	24.0	23.4	23.2	23.6	23.0	229	23.1
8	Coat	¥	9.6	4.3	5.5	2.3	22	2.6	2.4	2.8	2.8	2.7	2.9	2.7
	Residual (FO6) -Total	*	0.2	0.3	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Steam	*	0.2	0.3	0.5	0.9	0.0	0'0	0.0	9.0	0.0	0.0	00	0
100	Distillate (FOZ) - Total	32	0.1	0.1	1.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	00	0
0	Steam	*	0.0	0.0	00	0.0	0.0	0.0	0.0	0.0	0.0	0'0	90	0
-	CC	*	0.1	0.1	10	00	0.0	0.0	0.0	0.0	0.0	0.0	00	9
\$	CT	*	0.0	0.0	00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	00	0
6	Natural Gas -Total	*	68.2	69.9	67,8	70.8	70.7	6.9.9	712	70.2	69,6	6.93	689	697
-	Steam	×	15	3.5	17	1.6	0.9	0.5	0.3	5.0	0.4	0.4	10	0
5	SC	*	66.3	88.0	66.1	68.6	69.6	69.3	70.7	69.8	69.1	69.3	69.6	69
1	CT	*	6.0	54	00	9.4	0.2	0.1	0.1	0.1	0.1	0.2	1.0	0
4	Solar ²	28	0.2	0.1	0.1	0.5	0.5	0.5	1.0	1.0	1.0	1.0	1.0	1
5	PV	*	1.0	0.1	0.1	0.5	0.5	5.0	1.0	1.0	1.0	1.0	1.0	7
6	Solar Thermal	*	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	ö
E	Other *	*	0.1	90	22	2.0	2.1	2.5	1.9	2.6	2.8	3.1	32	
3			100	100	100	8	100	100	100	100	100	100	100	10
- 0 0 -	Source: A Schodules and The projected figures are Represents output from F Represents a forecast of	5 Actual D based o PPL's PV energy e	iats for Naxl (n estimated i and solar the xpected to be	Generation S Energy purcl rrmal facilitie purchased	Datar Centers R bases from SJI Ms. Qualitying	aport 1919. I Facilities, Inc	Jependent Pa	wer Produce	rs, elc, net of					



Michael A. Babb Chair, Hillsborough Randall S. Maggard

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Manatee

Polk

Treasurer, Hillsborough, Pinellas



Bartow Service Office 170 Century Boulevard Bartow, Florida 33830-7700 (863) 534-1448 or 1-800-492-7862 (FL only) 2379 Broad Street, Brooksville, Florida 34604-6899 (352) 796-7211 or 1-800-423-1476 (FL only) WaterMatters.org

Sarasota Service Office 6750 Fruitville Road Sarasota, Florida 34240-9711 (941) 377-3722 or 1.800-320-3503 (FL only)
 Tampa Service Office

 7601 U.S. 301 North (Fort King Highway)

 Tampa, Florida 33637-6759

 (813) 985-7481 or

 1-800-836-0797 (FL only)

| June 24, 2016

Mr. Moniaishi Mtenga, Engineering Specialist Division of Engineering Florida Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399-0850

Subject: Electric Utility 2016 Ten-Year Site Plans

Dear Mr. Mtenga:

In response to your request, the Southwest Florida Water Management District (District) has completed its review of the 2016 Ten-Year Site Plans for Duke Energy Florida, Florida Power & Light Company, Seminole Electric Cooperative and Tampa Electric Company. The District's review is being conducted pursuant to Section 186.801(2)(e), Florida Statutes, which requires the Public Service Commission to consider "the views of the appropriate water management district as to the availability of water and its recommendation as to the use by the proposed plant of salt water or fresh water for cooling purposes." Based on our review, all four utilities are proposing to construct new combustion turbine or combined cycle facilities at undesignated sites within the ten-year planning horizon.

The District offers the following technical assistance comments for consideration:

- The most water conserving practices must be used in all processes and components of the power plant's water use that are environmentally, technically and economically feasible for the activity, including reducing water losses, recycling, and reuse. If a lower quality water is available and is environmentally, technically and economically feasible for all or a portion of the proposed use, this lower quality water must be used.
- For new generating facilities proposed in the southern and much of the central portions of the District, there are additional water use constraints. These areas have been designated as Water Use Caution Areas. This designation has occurred in response to water resource impacts, such as salt water intrusion, lowered water levels in lakes and wetlands, and reduced stream flows, which have been caused by excessive ground water withdrawals. Regional recovery strategies are being implemented to address these adverse water resource impacts. Consequently, the District has heightened concerns regarding potential impacts due to additional water withdrawals.

Executive Director

Mr. Moniaishi Mtenga, Engineering Specialist June 24, 2016 Page 2

Early coordination with the District's Water Use Permit (WUP) staff is encouraged prior to submittal of any Site Certification or WUP applications. For assistance or additional information concerning the District's WUP program, please contact Darrin Herbst, WUP bureau chief in the District's Tampa office, at (813) 985-7481, extension 2014, or <u>darrin.herbst@watermatters.org</u>.

We appreciate this opportunity to participate in the review process. If you have any questions or require further assistance, please do not hesitate to contact me at (352) 796-7211, extension 4790, or james.golden@watermatters.org.

Sincerely,

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James J. Golden, AICP Senior Planner

JG



Date:July 1, 2016From:Richard Burklew, Bureau Chief, Water Use RegulationTo:Florida Public Service CommissionSubject:Review of 2016 Ten-Year Power Plant Site Plan for Electric Utilities

The relevant statute for ten-year review of Site Plans is Section 186.801, F.S.. The portion of this statute relevant to District review includes the following:

...In its preliminary study of each 10-year site plan, the commission shall consider such plan as a planning document and shall review:

(c) The anticipated environmental impact of each proposed electrical power plant site.....

(e) The views of appropriate local, state, and federal agencies, including the views of the appropriate water management district as to the availability of water and its recommendation as to the use by the proposed plant of salt water or fresh water for cooling purposes....

Individual Site Plan Reviews:

Florida Power & Light – The Site Plan includes the addition of the Okeechobee Clean Energy Center (OCEC), which is a proposed new facility planned for operation in 2019. OCEC will be authorized to use approximately 9 mgd of groundwater. However, the certification will require conversion to lower quality water sources when feasible. The Site Plan reflects information submitted and reviewed by the District during the site certification review process. District staff considered this information and recommended approval of the project to the District's Governing Board. The Governing Board approved its agency report regarding OCEC in March 2016. The Site Plan discusses two other potential sites in Alachua and Volusia Counties. Both of these sites are proposed as photovoltaic plants with minimal water resource needs. Beyond these three sites, no additional new significant resource needs until 2024 and 2025. The submitted Site Plan is suitable as a planning document.

Seminole Electric Cooperative – The Site Plan discusses addition of a total of 1700 MW by 2025, including four 224 MW natural gas Combustion Turbine (CT) units, one 741 MW natural gas Combined Cycle (CC) unit, and an additional 2 MW photovoltaic (PV) plant. Of these facilities, only the CC unit is proposed for wet cooling and the CT units will be air-cooled. None of the CC or CT units have been sited yet and water sources are not discussed. Potential site locations are in Gilchrist County and at the existing Seminole Generating Station (SGS) in Putnam County. The existing SGS uses surface water from the St. Johns River for cooling and,

presumably, if this site is selected for the proposed CC unit, could potentially be a source of cooling water for this unit.

The preferred future site for PV generation is at the existing Midulla Generating Station (Hardee County). This plant would have minimal water use obtained by water trucks or from existing onsite permitted resources. Submitted Site Plan is suitable as a planning document.

JEA – The Site Plan discusses continuation of the existing generating facilities, expiration of the agreement between JEA and Florida Power & Light for the joint ownership of the St. Johns River Power Park and expiration of the wholesale power agreement to supply Florida Public Utilities. The plan forecasts additional power purchased from two new nuclear units at the Plant Vogtle in Georgia. Based on expiration of wholesale and joint ownership agreements and the commitment to purchase nuclear power, there is no anticipated expansion of water use at the existing power generation facilities beyond what is currently permitted. The submitted Site Plan is suitable as a planning document

Orlando Utilities Commission (OUC) – The OUC Site plan discusses continued operation of existing facilities, power purchase and sales contracts, renewable energy and sustainability initiatives and future demand projections. Consideration of OUC's existing generating resources and OUC's current base case load forecast indicates that OUC is expecting to have adequate capacity to satisfy forecast reserve margin requirements until the summer of 2021. Based on the magnitude and timing of OUC's projected need for capacity, it has been assumed for purposes of the Ten-Year Site Plan that OUC will have to add combined cycle capacity to meet the projected capacity requirements. It was noted that OUC's existing Stanton Energy Center and Indian River sites may accommodate future generating unit additions. However, OUC has not made any commitments to new capacity additions, and will continue to evaluate its power supply requirements and alternatives as part of its planning processes. There is no defined or declared expansion of water use at the existing power generation facilities beyond what is currently permitted. The submitted Site Plan is suitable as a planning document.



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MEMORANDUM

Date:	July 1, 2016
То:	Shaun Cullinan, Planning and Zoning Official
From:	Matt Trepal, Principal Planner and Ken Quillen, Planner III
Subject:	Review of <u>Ten Year Power Plant Site Plan 2016-2025</u> for Florida Power and Light

The Comprehensive Planning Division has completed their review of the Florida Power and Light's Ten Year Power Plant Site Plan 2016-2025 and has the following comments.

This ten year Plan includes the Babcock Solar Energy Center, which is a new 74.5 MW photovoltaic (PV) electric generating plant in Charlotte County near the developing Babcock Ranch Community in East County. Related facilities include the Tuckers substation, located near the Babcock Solar Energy Center, and the Hercules substation, located near Fire Station No. 9 and the Babcock Ranch Community. Transmission lines are also being constructed linking these two substations. Charlotte County has been aware of this proposed new power generation plant for some time. These facilities are now under construction and are intended to be completed and in service by December of this year. This facility will serve the planned Babcock Ranch Community, which is now under construction.

Planning staff believes that this is a suitable planning document which describes its existing electric generation and distribution capacity (owned or purchased) as well as projected future resource needs. This planning document states that it was designed to focus on projected supply side additions of electric generation capability and the locations for these additions. We believe that FPL has done a good job of calculating future needs, or load, and generating capacity based on past and present demand by traditional land uses, such as, residential, commercial, industrial uses. However, there is an emerging new demand for electricity from plug-in electric vehicles.

Staff understands that it may be difficult to anticipate how fast this new demand may grow in the next five to ten years and this is a subject of much discussion and speculation today in the planning field. This new market could create a tremendous new demand for electricity. The Plan has taken this into account and does forecast an additional load of approximately 1,091 GWh by 2025 from new plug-in vehicles. The only suggestion our planning staff would make regarding this Plan is that more information regarding how the anticipated future demand for plug-in electric vehicles is being calculated. Maybe the Florida Department of Motor Vehicles can use licensing information to determine the number of plug-in electric vehicles there are each year so that the rate of increase in numbers, and therefore demand, could be watched and monitored accordingly.

> **Community Development Department** 18400 Murdock Circle, Port Charlotte, FL 33948-1068 Phone: 941.743.4903 | Fax: 941.743.1292



1.866.522.SACE www.cleanenergy.org

> P.O. Box 1842 Knoxville, TN 37901 865 637 6055

46 Orchard Street Asheville, NC 28801 828.254.6776

250 Arizona Avenue, NE Atlanta, GA 30307 404.373.5832

P.O. Box 310 Indian Rocks Beach, FL 33785 954.295.5714

> P.O. Box 13673 Charleston, SC 29422 843.225.2371

October 3, 2016

Florida Public Service Commission 2540 Shumard Oak Boulevard Tallahassee, FL 32399

Re: 2015 Ten Year Site Plans

Dear Commissioners and Staff:

Thank you for the opportunity to Southern Alliance for Clean Energy (SACE) to provide written comments on the utilities' 2016 Ten Year Site Plans and opportunities for providing additional customer value.

SACE is a non-profit, non-partisan clean energy group that advocates for lower cost, lower risk resources in meeting electricity demand. That includes moving away from high risk, high cost resources such as coal, and diversifying the state's energy mix into resources with vast potential – such as capturing more energy efficiency and integrating higher levels of clean, abundant and low cost solar power.

SACE supports policies and plans that meaningfully increase rooftop solar, larger commercial installations, and utility-scale solar. They are all part of a healthy solar market. Solar energy benefits Florida by diversifying its resource mix to include a resource that presents no long-term cost risk, an important hedge against the likelihood that natural gas fuel prices will increase over time. Furthermore, solar arrays require no water for generation and produce no emissions subject to regulatory abatement.

All forms of solar power are seeing continuing price drops, with utility scale power purchase agreements now being signed at 3.5 to 5 cents per kilowatt hour (kWh).ⁱ Even though Florida is one of the largest states, it ranked just 18th in total megawatts of solar installed in 2015.ⁱⁱ As it relates to utility-scale solar, there is a significant and growing opportunity to expand and bring Florida to the forefront of this industry where it belongs.

SACE recommends that the Commission require the utilities to study supply-side solar as a resource, and provide for more market entry for supply-side solar projects. To that end, we offer several recommendations below.

Require utilities to study solar as a supply-side resource in the resource planning process

To establish effective market competition and Commission regulatory oversight of solar energy supply decisions, the Commission should reform resource planning rules. Florida's current planning requirements include four steps: the Ten-Year Site Plan (TYSP); Request for Proposal (RFP) process; Need Determination; and Site Certification. Solar power projects under 75 MW are effectively exempt from these steps, except for a requirement to revise the TYSP to include those projects (but there is no clear deadline for such revisions as discussed below).

Utility resource plans are required to be described in an annual TYSP, which has extensive information and data requirements. The TYSP is submitted to the Florida PSC annually by electric generation utilities with a generating capacity greater than 250 MW.ⁱⁱⁱ The Commission reviews the plans within nine months following submission and reports its findings, along with any comments or recommendations, to the Florida Department of Environmental Protection and the utilities filing a plan. The Commission also creates a statewide TYSP from the provided information.

The Commission makes a preliminary study of each plan and classifies it as "suitable" or "unsuitable." It should be noted that "suitability" has not been defined in statute or rule, but unsuitability may be remedied by the utility providing additional data.^{iv} The Commission may suggest alternatives to the plan. It is recognized that 10-year site plans submitted by an electric utility are *tentative information* for planning purposes only and may be *amended at any time* at the *discretion of the utility*.^v

For any planned generating unit over 75 MW, the utility initiates regulatory oversight when the unit is identified as the utility's next planned generating unit in a TYSP revision. Until that point, any discussion of a planned generating unit is merely informational and does not appear to have any regulatory significance. Identification of the next planned generating unit is important for a number of reasons, including the practice of basing the avoided capacity rate in standard offer contracts on the next unit (and not, for example, on the opportunity to defer subsequent units or change the type of the next unit). Even more important is that Commission rules identify this unit as the benchmark for the alternatives analysis.

The only requirement for a Florida utility to consider alternatives to the next planned generating unit is the Commission's rule requiring a RFP process for projects over 75 MW. According to that rule, "The use of a RFP process is an appropriate means to ensure that a public utility's selection of a proposed generation addition is the most cost-effective alternative available."^{vi} The Commission's rules do not provide for any public review of the alternatives analysis.

However, by benchmarking alternatives against the "price and non-price attributes of its next planned generating unit," the RFP rule effectively excludes any requirement for the utility to consider alternative configurations of technology that might be more cost-effective in the long-term. FPL's RFP for 1,052 MW (March 16, 2015) provides a good example of how alternative resources are disadvantaged by such a benchmark process. Under the terms of the RFP, any proposed resources were compared to FPL's Next Planned Generating Unit, the Okeechobee Clean Energy Center, a 1,622 MW combined cycle natural gas plant.^{vii}

According to the RFP, the "firm capacity and energy proposed" must be "fully dispatchable under the operational control of FPL" which would operationally exclude solar PV resources from providing even a portion of the energy, not to mention any firm summer capacity.^{viii} In short, the RFP process is not capable of evaluating any alternative that is not a one-for-one replacement of the company's next planned generating unit and thus does not ensure that the selected resource is the most cost-effective means to meet the utility's identified resource needs.

Of course, Florida's utilities do undertake a more comprehensive analysis of resource needs beyond that in the RFP, utilizing what is *presumed* to be a thorough IRP analysis including consideration of resource alternatives through a computer model optimization process. However, this process is not available to the public for review during either the TYSP or the RFP process. It is only when the results of the RFP process are made known,^{ix} and a request for a need determination is made, that the utility's assumptions and methods for considering alternatives can be evaluated by interested parties and the Commission.

This review is ill-timed. By the time that a utility files a request for a need determination, the utility has likely waited until what it views as the last possible moment for building the power plant. At this point, the utility has constrained its options due to schedule and potentially missed opportunities. While significant changes can and have been made, they are typically substitutions of like resources, such as the recent Duke Energy Florida substitution of a purchase of an existing combined cycle gas plant for construction of a new combined cycle gas plant.

Together these policies form a less than coordinated state planning process. The assumptions used in the utility resource planning process are only revealed through intervention and discovery in a need determination (or FEECA) proceeding. Moreover, the Ten Year Site Plan process does not provide opportunities for stakeholder input of the type found in other Southeastern states' IRP processes. The benefit of an integrated resource plan (IRP) is that it allows for meaningful stakeholder involvement and the consideration of alternate planning scenarios, which tends to place all resources on a "level playing field." Hence, Florida customers may be shouldering unnecessary costs from a less than optimal resource planning process, and the policies and programs recommended here would help to ensure that utilities are pursuing the most effective, least-cost options for electricity generation.

In order to promote the development of supply-side solar systems, the Commission could initiate a rulemaking to revise the Ten-Year Site Plan process to incorporate best practices for integrated resource planning.^x Of particular interest would be the opportunity to ensure that the characterization of the cost and performance of solar resources is reasonable and unbiased, that the study methods are also themselves free of unreasonable bias, and that the Company leverages the resource planning process to properly evaluate a variety of market-supplied and self-build resource alternatives. To effectuate such reforms, the Commission could revise its rules to require a periodic review of the utility's entire IRP (such as every two years) or could require a utility to submit its IRP for review at least two years in advance of an anticipated certification proceeding.

Establish a process for selecting cost-effective solar resource projects, including RFPs

Even if a Florida utility determines that solar resources are the most cost-effective available, it is not clear under what Commission rules a utility would request a determination of need. As discussed above, for any solar facility 75 MW or greater, §403.503, Fla. Stat. requires a determination of need by the Commission. However, Commission rules only prescribe the content of petitions for "Fossil, Integrated Gasification Combined Cycle, or Nuclear Fuel Electric Plants."^{xi}

SACE recommends that the Commission initiate a rulemaking proceeding to revise Chapter 25-22 to incorporate a process for a need determination for renewable energy resources, particularly solar, taking into consideration differing performance characteristics. For example, a utility may reasonably wish to seek a determination of need for a large solar (or other renewable resource) facility solely on the basis that the capital investment will result in a more cost-effective method of supplying electricity to its customers, even in the absence of a need for capacity. The investment may help to defer fuel, operating and maintenance costs, or free up energy for resale to other utilities during peak periods, resulting in an overall cost savings. We also recommend that the Commission identify best practices, such as long-term contracts, similar to the Gulf Power solar PPAs, that ensure the competitive solicitation process results in the most cost-effective outcome. For example, in order to meet a need (or cost-effective opportunity) for solar power in excess of 75 MW, a utility might choose a reverse auction mechanism to, as SEIA describes it, "ensure that developers are paid a price that is sufficient to bring projects online, but also provide ratepayer protection against "overpayment."^{xii}

Furthermore, we would recommend that the Commission make this RFP process available, and encourage its use, for all utility-scale solar projects. Economies of scale for utility-scale projects are often achieved at 20 MW, and few projects are constructed over 100 MW in scale (particularly in a landscape with as much land use variety and constraint as Florida). Thus, the 75 MW threshold for a need determination is an unwieldy threshold for triggering the opportunity to utilize a RFP process or obtain clear approval from the Commission for the costs and prudence of a substantial generation facility.

Solar standard offer contract

We recommend the establishment of a solar-specific standard offer contract, including a contract avoided cost rate, for solar Qualifying Facilities with a capacity of up to 5 MW. Florida rules and utility practice effectively exclude small solar projects from realizing the benefits of the standard offer contract available to other small power generators under the federal Public Utility Regulatory Policies Act (PURPA). PURPA is meant to increase energy independence in the United States by requiring states to establish the prices retail utilities must pay to third-party renewable energy developers – thus giving small developers a market for their power.

Yet, in practice in Florida, solar Qualifying Facilities are ineligible for any capacity payment due to the minimum performance standards for the delivery of firm capacity.

The system size in the standard offer contract is limited to a mere 100 kW.^{xiii} Developers tell us

that there is great interest for projects larger than this limit. In fact, it is not unusual for business customers to install larger systems, either through a developer or with their own financing. However, these customers may not wish to enter into expensive negotiations with the utility, and will desire a streamlined process such as a meaningful standard offer contract may provide.

If a solar developer does wish to negotiate a contract for a solar project over 100 kW, such contracts are entirely at the utility's discretion. There is limited legal basis for any party to challenge a utility's decision to refuse a contract, even if it is at the same time negotiating another similar contract at a higher price.

Policies such as these will help Florida realize more solar potential at the utility scale level. The Florida Reliability Coordinating Council's (FRCC) presentation during the Ten Year Site Planning Workshop show solar expanding in Florida by only 1445 MW in the next ten years. By comparison, nearly half that amount is already installed on Georgia Power's system, and up to 1900 MW more of renewable energy may be added by 2021. Florida has greater solar potential than our neighbor to the north, and we ought to ensure that this state's policies do not create an unnatural barrier to taking advantage of our vast potential.

Moving away from coal

Many of the state's coal-fired power plants remain in the utilities' Ten Year Site Plans through the planning period.

This assumption is worth taking another look at, as keeping coal plants online is actually subject to a number of risks. There is good reason to plan for the case that the end of a unit's useful life falls within the next ten years. Utilities should demonstrate that they have factored these risks in, and publicly disclose scenarios in which coal-fired units are taken offline, including the relative costs of retirement compared with the continued costs and associated ratepayer risks of maintaining a coal-fired unit.

Coal is becoming a more costly choice. Coal-fired power plants have been dispatched less frequently for a number of reasons, but primarily because they are not cost-effective relative to natural gas-fired power plants. Yet many operational costs of coal plants accrue whether the plant runs or not. As a result, the cost per megawatt-hour (MWh) tends to increase when plants are run less frequently.

C.D. McIntosh Unit 3, a coal-fired unit operated by Lakeland Electric (and co-owned with Orlando Utilities Commission), exemplifies this trend. In a report commissioned by SACE, David Schlissel provides the following chart showing declining power production at the plant.^{xiv}





¹ The October 1 through September 30 Fiscal Years shown in Figures 1 and 2 are used in the annual utility reports published by Lakeland Electric and OUC.

The report also compares the rising cost of operating the plant with the falling cost of power available on the Florida market from natural gas.



Figure 11: Average Production Costs - McIntosh Unit 3 vs. Natural Gas-Fired Combined Cycle Plants in Florida.⁶

Competition may not fully explain the reduced dispatch rate. The report also notes that the Equivalent Forced Outage Rate for the plant is unusually high; this suggests substantial maintenance issues, and in fact subsequent to the publication of this report, Lakeland Electric took the plant out of service for maintenance for months. While these issues may be plant-specific; their significant presence at this plant, one of Florida's newer coal-fired plants, adds

to the need for caution in relying on coal-fired plants far into the future.

Adding to the lack of cost competitiveness are regulatory compliance liabilities. The regulations provide much needed public health and environmental protections for Floridians. Yet, in order to comply with these standards, many plants will need significant upgrades.

For example, Gulf's Crist units 4 and 5 and JEA's Northside units use once-through cooling systems that suck massive amounts of water from the river and return most of it to the water body at a higher temperature. Both should anticipate that in the plant's next water permitting cycle, that the plants will need to make provisions to reduce thermal impacts, likely by adding a cooling tower, upgrades with costs in the hundreds of millions of dollars.^{xv}

A cooling tower would also help meet modern standards for prevention of fish, fish eggs, and other wildlife from getting caught or sucked into the plant's intake, another regulatory obligation under section 316b of the Clean Water Act (CWA), which will apply upon renewal of the units' NPDES permits.

Meanwhile, Tampa Electric has already applied for cost recovery of \$400,000,^{xvi} just to study what will be needed to bring its Big Bend plant into compliance with new Effluent Limitation Guidelines (ELGs), which will come into play in its next CWA permit cycle. With such significant costs just for the studies, one can safely anticipate that the cost of actually converting to dry ash handling, and controlling heavy metals in the discharge water, will be significant, possibly enough to make retirement a more cost-effective option.

Coal cost risks are further increased by the need to comply with the federal Coal Combustion Residuals Rule (CCR Rule or Coal Ash Rule), which is a particular challenge for Florida coal plant operators. By 2018, operators will need to show their ash storage is not compromised by locational factors such as sinkhole-prone geology, proximity to aquifers, or being in a floodplain. Many Florida plants may be unable to comply due to Florida's geology, and may face the costly alternative of shipping the ash out of peninsular Florida.

Plant McIntosh is once again a salient example. Although dry ash storage is already in use at the site, a recent hydrogeological study found the likelihood that at a sinkhole will form under the ash landfill. Such a sinkhole could drop ash and contaminated groundwater into the Floridan aquifer. Groundwater flows in the area, as well as the presence of nearby sinkholes including at least two on the plant property, were used to determine this likelihood.^{xvii,xviii}

Utilities' and FRCC's presentations at the Ten Year Site Plan workshop on September 14, 2016 indicated that impacts of the Clean Power Plan on generation choices would be addressed in the future, once federal courts resolve the challenge of the rule. We strongly urge utilities not to wait, as there are no-regrets clean energy choices that can be made now. Nevertheless, the Clean Power Plan is just one of many upcoming public health and environmental protection rules that utilities will need to address; as we outline here, there are others that will impact prudent decision-making in the resource planning process.

Conclusion

It is prudent to investigate these risks now, and research alternatives. Piecemeal decisionmaking needlessly exposes Florida's families and business to higher priced power while also robbing them of the wide-ranging benefits of clean water and clean energy resources that are at record low prices.

SACE appreciates the opportunity to offer these comments and looks forward to working with the Commission and its staff in the resource planning process and associated dockets to reduce customer risk and realize additional value for customers.

Sincerely,

/s/ George Cavros

Florida Energy Policy Attorney, Southern Alliance for Clean Energy

/s/ Amelia Shenstone

Campaigns Director, Southern Alliance for Clean Energy ⁱⁱⁱ R. 25-22.071, F.A.C. Pursuant to Rule 25-22.071(1), F.A.C., only generating electric utilities with an existing capacity above 250 megawatts (MW) or a planned unit with a capacity of 75 MW or greater are required to file with the Commission a Ten-Year Site Plan, at least once every two years. In 2014, 11 utilities met these requirements and filed a Ten-Year Site Plan, including 4 investor-owned utilities, 6 municipal utilities, and 1 rural electric cooperative. The investor-owned utilities, in order of size, are Florida Power & Light Company (FPL), Duke Energy Florida, Inc. (DEF), Tampa Electric Company (TECO), and Gulf Power Company (GPC). The municipal utilities, in alphabetical order, are Florida Municipal Power Agency (FMPA), Gainesville Regional Utilities (GRU), JEA (formerly Jacksonville Electric Authority), Lakeland Electric 8 (LAK), Orlando Utilities Commission (OUC), and City of Tallahassee Utilities (TAL). The sole rural electric cooperative filing a 2015 Plan is Seminole Electric Cooperative (SEC). Collectively, these utilities are referred to as the Ten-Year Site Plan Utilities (TYSP Utilities).

^{iv} Id.

^v § 186.801(2), Fla. Stat.

^{vi} R. 25-22.082, F.A.C.

^{vii} Florida Power & Light Company, 2015 Request for Proposals to Meet Generation Capacity Needs Beginning in 2019, p. 40.

^{viii} *Id.*, p. 5.

^{ix} A utility's IRP analysis may also be obtained during the goal-setting proceeding under the Florida Energy Efficiency and Conservation Act (FEECA), which occurs every five years. However, utility-scale solar generation is not within the scope of that proceeding.

^x Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*, Regulatory Assistance Project (June 2013).

^{xi} R. 25-22.081, F.A.C.

^{xii} Solar Energy Industries Association website. For example, California Public Utilities Commission's Renewable Auction Mechanism.

^{xiii}R. 25-17.250, F.A.C. *See also* R. 25-17.0825(1)(b), F.A.C. (Those qualifying facilities wishing to negotiate a contract for the sale of firm capacity and energy with terms different from those in a utility's standard offer contract may do so pursuant to subsection 25-17.0832(2), F.A.C. Where parties cannot agree on the terms and conditions of a negotiated contract, either party may apply to the Commission for relief pursuant to Rule 25-17.0834, F.A.C.)

^{xiv} Schlissel, David, *The Time is Right to Retire C.D. McIntosh Unit 3*. Institute for Energy Economics and Financial Analysis, October, 2015, at: http://ieefa.org/study-concludes-costly-coal-plant-in-lakeland-fla-should-be-retired-in-favor-of-solar-expansion-and-energy-efficiency-initiatives/. Attached.

^{xv} Section 316a, Clean Water Act

^{xvi} Tampa Electric Company, *Petition of Tampa Electric Company for approval of a new environmental program for cost recovery through the Environmental Cost Recovery Clause*, Florida PSC Docket No.160027. Filed Feb. 2, 2016. ^{xvii} Diana Csank, *Memorandum to Joel Ivy, General Manager, Lakeland Electric Re: Lakeland Electric Should Cease*

Burning Coal and Clean Up the CCR at McIntosh Unit 3 for Economic, Regulatory, and Public Health Reasons, January 25, 2016. Attached.

^{xviii} Stewart, Mark. Preparing for the U.S. Environmental Protection Agency's Coal Combustion Residuals Rule: Technical Assessment of the C.D. McIntosh, Jr. Power Plant CCR Storage and Disposal Facilities, January 25, 2016. Attached.

ⁱ Solar Energy Industries Association/GTM Research, *Solar Market Insights 2016, Q3*, September 12, 2016, at http://www.seia.org/research-resources/solar-market-insight-report-2016-q3 ⁱⁱ *Id*.



October 10, 2016

Via electronic filing and electronic mail

Chairman Brown, Comm'rs. Brisé, Edgar, Graham, Patronis Florida Public Service Commission 2540 Shumard Oak Blvd. Tallahassee, Florida 32399-0850

Re: Planning for least-cost electric service in Florida

Dear Commissioners:

Rapid changes in the electric sector make integrated resource planning more important than ever. Yet Florida electric utilities, especially the investor-owned utilities (IOUs), barely have any plans at all—besides adding natural gas-burning generation, which dwarfs everything else in their plans.¹ Sierra Club respectfully urges the Commission to reject them and require revised plans for four main reasons:

- 1. Florida law requires utilities to provide least-cost service, but the utilities are unprepared to do so because they fail to perform options analyses; the utilities thus never try to (nor could they) square their gas-laden plans with the alternatives available to them in the market.²
- 2. The proposed gas generation violates the least-cost standard because this generation is inherently high cost and high risk.
- 3. The proposed gas generation also violates the least-cost standard because it reduces fuel diversity and foregoes cost-effective renewables and energy efficiency, thereby pushing Florida's all-time high gas reliance, 71% of the state generation total, even higher, to 74%.
- 4. With no shortage of cost-effective alternatives in the market, especially renewables and energy efficiency, the only way to explain the utilities' gas generation proposals is that they aim to benefit entities other than customers.

¹ Unless stated otherwise, "plans" refers to ten-year site plans, and "utilities" refers to those that file them.

² To their credit, Staff issued extensive data requests. The responses, however, cannot cure the unlawful plans.

By now, it is unmistakable; the IOUs/their affiliates are investing heavily in every aspect of gas generation and infrastructure with a perverse incentive to continue to do so. They pass the resulting added cost of service onto their captive customers, and the resulting windfall profits to shareholders.

It is imperative that the Commission intervene and reject all of the unlawful plans. Revised plans should follow as soon as practicable. For the IOUs, this should be no later than April 1, 2017, the annual deadline for revised plans, to minimize the fallout from their conflict-ridden plans.

As we discuss below, at least one Florida utility, Lakeland Electric, recently undertook an assessments of its options under different scenarios, showing this is eminently doable. Moreover, practically all of the Florida utilities, with the glaring exception of the IOUs, have issued requests for proposals (RFPs) for renewables and found no shortage of cost-effective solar generation options in the Florida market. When done well, market assessments like these promote competition, stakeholder participation, and ultimately transparent, data-driven options analyses to guide utilities to least-cost investments.

The stakes are high. Every year that passes without plans for least-cost electric service further jeopardizes the competitiveness of Florida's economy and the wellbeing of its residents. This includes the millions of low-income/fixed-income Floridians who already face a disproportionate energy burden.

DISCUSSION

The Commission should reject the plans because they violate the least-cost standard under Florida law; the revised plans should include robust options analyses focusing on renewables and energy efficiency.

We divided this discussion into three parts: First, we discuss the applicable least-cost standard under Florida law. Second, we show that the utility plans violate this standard, and the Commission should reject them. Finally, we conclude by urge the Commission to obtain revised plans, including the chronically missing options analyses, as soon as practicable, so that the Commission can meaningfully audit the utilities and ensure they are prepared to achieve least-cost service.

I. Under Florida's least-cost standard, electric utilities must develop robust options analyses focusing on renewables and energy efficiency to guide the utilities to least-cost investments to serve their customers.

Florida law requires electric utility service to be least-cost. As the Florida Supreme Court affirmed, under this standard, the state's electric utilities must "t[ake] every reasonably

available prudent action to <u>minimize</u> [their cost of service]."³ Planning is the critical first step. Per Commission rules, the utilities must develop and disclose "sufficient information to reassure the Commission that an adequate and reliable supply of electricity at the <u>lowest cost possible</u> is planned."⁴

A. Utilities must develop robust options analyses to guide them to least-cost investments.

Options analyses are routine in the business world, and essential for the utilities to meet the least-cost standard under Florida law. This is a matter of Commission precedent and common sense.⁵⁶ Options typically available to utilities include but are not limited to:

- Alternatives to conventional generation, such as renewables⁷ and energy efficiency;⁸
- Alternatives identified through market assessments such as the request for proposal process under Rule 25-22.082, F.A.C (i.e., the Commission's competitive "bid rule");⁹

⁵ Order No. PSC-11-0547-FOF-EI, at 82, issued on November 23, 2011, in Docket No. 11 0009-EI, <u>In re:</u> <u>Nuclear cost recovery clause</u>; *See also* Order No. PSC-11-0547-FOF-EI (redacted Final Order) (noting approval of utility's rate increase request upon finding "no practical alternative") issued on November 23, 2011, in Docket No. 11 0009-EI, <u>In re: Nuclear cost recovery clause</u>; *cf.* Order No. PSC-11-0547-FOF-EI (redacted Final Order), at 6 (reviewing whether utilities properly considered "all available" demand-side and supply-side conservation and efficiency measures) issued on December 16, 2014, in Docket No. 130205-EI, <u>In re: Commission review of numeric conservation goals (Florida Public Utilities Company)</u>.

⁶ Order No. PSC-11-0547-FOF-EI, at 82 (noting the review of "all available options" is "routine procedure in the business world," including the electric utilty industry as it undertakes "long-term, complex project[s]") issued on November 23, 2011, in Docket No. 11 0009-EI, <u>In re: Nuclear cost recovery clause</u>.

⁷ Unless otherwise noted, the terms "renewables" and "renewable energy" refer to the same energy resources. *See generally* Section 366.91(2)(d), F.S, (defining "renewable energy" in pertinent part as "electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power").

⁸ See, e.g., Order No. PSC-14-0696-FOF-EU, at 39, issued on December 16, 2014, in Docket No. 130205-EI, In re: Commission review of numeric conservation goals (Florida Public Utilities Company) ("demand-side management is an alternative resource to generation plants and should be evaluated similarly for reliability and economic impacts."); *See also* Order No. PSC-16-0032-FOF-EI, at 13–15, issued on January 19, 2016, in Docket No. 150196-EI, In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company; *See also* Order No. PSC-11-0547-FOF-EI, issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause ("In 2006, we stated that utilities should not assume the automatic approval of natural gas-fired plants.").

³ Gulf Power Co. v. Florida pub. Service Com'n, 453 So.2d 799, 802 (Fla. 1984).

⁴ Rule 25-22.072(1), F.A.C., incorporating by reference Form PSC/RAD 43-E (11/97), at 4; *cf.* Section 366.82(5)(b)(requiring "analysis of various policy options ... to achieve least-cost strategy").

- Incremental capacity increases;¹⁰
- Earlier or later extremes of commercial operations date;¹¹ and
- Retaining one vendor, retaining multiple vendors, or building the generation itself ("self-build").¹²

Robust options analyses are those that develop information on the economics of these wide ranging options under various scenarios.¹³ A simple comparison of the status quo and one option is indefensible.¹⁴

B. Utilities must focus on renewables and energy efficiency.

Florida Statutes brim with directives to diversify the fuels and the technologies the utilities use to serve customers.¹⁵ More specifically, they emphasize and reiterate that Florida's reliance on inherently risky natural gas imports is a problem, and that cost-effective renewables and energy efficiency are solutions that are in the public interest. As the utilities perform options analysis, they must therefore focus on renewables and energy efficiency as part of their plan to serve customers at the least-cost.

⁹ See, e.g., Order No. PSC-06-0779-PAA-EI, at 3, issued on September 19, 2006, in Docket No. 060426-E1, In re: Petition for exemption under Rule 25-22.082(18), F.A.C., from issuing request for proposals (RFPs), by Florida Power & Light Company ("the RFP process provides us with valuable information on the available capacity alternatives and is a valid tool for evaluating the cost-effectiveness of proposed generating units.").

¹⁰ See, e.g., Order No. PSC-13-0505-PAA-EI, at 13, issued on October 28, 2013, in Docket No. 130198-EI, <u>In</u> re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company; See also Florida Public Service Commission, States' Electric Resurfacing Activities (1997); See also F.L. House of Representatives, Committee on Utilities and Communications, Overview of the Electric Industry, 27 (2000), available at https://goo.gl/uKDBP6.

¹¹ See, e.g., Order No. PSC-11-0547-FOF-EI, at 82.

¹² See, e.g., Order No. PSC-08-0749-FOF-E, issued on Nov. 12, 2008, in Docket No. 080009-EI, <u>In re: Nuclear cost recovery clause</u>; See also Order No. PSC-09-0783-FOF-EI, issued on Nov. 19, 2009, in Docket No. 090009-EI, <u>In re: Nuclear cost recovery clause</u>; See also Order No. PSC-11-0547-FOF-EI.

¹³ See Sierra Club Comments (Oct. 16, 2013) (hereinafter "Sierra Club 2013 Comments") (discussing best practices in integrated resource planning including options analysis), *available at* http://goo.gl/h9RHeT.

¹⁴ *Gulf Power Co. v. Florida pub. Service Com'n*, 453 So.2d 799 (Fla. 1984) (affirming Commission disallowance of costs incurred pursuant to utility's failure to review other other options beyond its preferred proposal for years).

¹⁵ For a recap of the relevant provisions in Florida Statutes, see Sierra Club Post-Hearing Brief in Docket No. 160021 (Sept. 19, 2016), *available at* https://goo.gl/X6QJ91.

II. The Commission should reject the plans because they are in no way least-cost.

The plans fail to meet the least-cost standard under Florida law for many reasons. The most glaring one is that the utilities failed to present any options analyses. The utilities thus failed to reconcile their inherently high-cost, high-risk gas generation with the abundant, competitive renewables and energy efficiency in the market available to them, and in the case of the IOUs, plainly have a conflict of interest behind the omission.

A. The utilities failed to present any options analyses in their plans.

This year, the utilities continued their practice¹⁶ of presenting the Commission just their preferred generation proposals and asserting they considered/will continue to consider their options.¹⁷ This violates the unambiguous requirement in Florida Statutes that the Commission "shall review"—"possible alternatives to the proposed plan[s]" of the utilities.¹⁸ If the utilities present no data or analyses on the options/alternatives available to them in the market, they preclude the Commission from performing its plain duty under Florida Statutes.

To be sure, the utility responses to Staff data requests do not cure the unlawful plans. For all of the planned generating units, Staff asked the utilities to "identify the next best alternative that was rejected for each unit."¹⁹ The fact that Staff had to ask for this information underscores how devoid the plans are of options analyses. The utility responses do, too. They are high-level comparisons between each <u>planned gas</u> generating unit and another gas generating unit. That is all. That is the sum total of the options analyses before the Commission.

No one can square the dearth of information presented by the utilities with the leastcost standard under Florida law. As discussed in Section I (above), the standard requires the utilities to conduct robust options analyses, focusing on renewables and energy efficiency, so that they are prepared to take <u>every</u> reasonably available prudent action to minimize cost of

¹⁶ See Sierra Club 2013 Comments (noting the unlawful practice), *available at* http://goo.gl/h9RHeT; Sierra Club Comments (Dec. 15, 2015) (hereinafter "Sierra Club 2015 Comments") (noting the same), *available at* https://goo.gl/IWbsDH.

¹⁷ See e.g., Florida Power & Light Company's 2016 Ten-Year Power Plant Site Plan (hereinafter "FPL 2016 TYSP"), Chapter III.C (noting "significant factors that either influenced the current resource plan presented in this document or which may result in changes in this resource plan in the future" but omitting data on or comparative analysis of those factors/ changes; i.e., options analysis); *available at* https://goo.gl/wgWn9Y; *see generally* 2016 Ten-Year Site Plans (similar omissions) *available at* https://goo.gl/1y17w9.

¹⁸ Section 186.801(2), F.S.

¹⁹ Staff data request no. 42.

service, and Florida's reliance on inherently risky natural gas imports. Working up the details of just one gas generation plan and then, at Staff's prodding, working up another is nowhere near the robust options analysis that is routine and essential to prepare electric utilities to provide least-cost service. The Commission therefore should reject the plans.

B. The utilities failed to reconcile their inherently high-cost, high-risk gas generation proposals with the abundant, cost-effective renewables and energy efficiency in the market available to them.

The plans are indefensible and the Commission should reject them for the additional reason that they would increase gas generation, which is inherently high cost and high risk, especially as demand is down. The utilities never tried to (nor could they) reconcile their plans with the abundant, cost-effective renewables and energy efficiency in the market available to them.

1. Demand is down and the growth projected by utilities has not materialized for eight straight years, a trend no one can square with adding gas generation in large, inflexible increments.

Since it peaked in 2005, demand for electricity across Florida is down. This is not due to the Recession alone, as the Commission itself noted.²⁰ Previous utility load forecasts required downward revisions due to slower-than-projected growth <u>for eight straight years</u>, including the last three.²¹ The utilities themselves acknowledge that usage per customer is down.²²

Yet the utilities project peak demand will somehow grow faster than one percent annually between 2016 and 2025 (net firm peak demand)—more than half again the rate experienced between 2004 and 2015 (0.76 percent CAAGR). This is inconsistent with, for example, the U.S. Energy Information Administration's lower projection of a 0.7 percent annual growth rate through 2025.²³

More importantly and obviously, demand projections are never as good as verified actual data, and the actuals have shown a consistent downward trend. The best options for

²⁰ FPSC, Review of the 2015 TYSPs, at 22, *available at* https://goo.gl/DTGoX1.

²¹ Compare FRCC 2014 Presentation, at 7 ("Forecasted energy sales and winter firm peak demands are lower in 2014 TYSP compared to 2013 TYSP and forecasted summer firm peak demands are higher from 2017 forward."), *available at* https://goo.gl/ACqiVT; FRCC 2015 Presentation, at 7, ("forecasted energy sales and firm peak demands are lower in 2015 TYSP compared to 2014 TYSP"), *available at* https://goo.gl/mn4gUf; and FRCC 2016 Presentation, at 8 "forecasted energy sales and firm peak demands are lower in 2016 TYSPs"), *available at* https://goo.gl/UScXlk.

²² Utility responses to Staff data request no. 10.

²³ This is EIA's projection for Florida as well as other South Atlantic states.

Florida therefore are those that (1) keep demand down to reduce cost (i.e., demand-side management), and (2) meet any growth in demand with incremental supply that closely matches the growth (i.e., flexible supply). The utilities failed to present <u>any</u> such options. The only option the utilities did present—large, inflexible gas generation additions—flies in the face of the market reality just described. It is indefensible also because the additional capacity maintained by the IOUs consistently exceeds the levels needed for an adequate and reliable supply of electricity.²⁴

2. Gas generation is inherently high cost and high risk.

The Commission should not accept the utilities' complacency about the costs and risks of gas generation, especially as the state's reliance on natural gas is already at an all-time high—71% of the total generation.²⁵ The utilities propose to add another five gigawatts— pushing that up to 74% by 2025.²⁶ Even the smallest proposed increment exceeds 180 MW,²⁷ with projected capital costs measured in millions of dollars, and book lives in decades. Moreover, with the exception of Orlando Utilities Commission (OUC) and Florida Power & Light Company (FPL), the utilities propose inherently less efficient peaking generation—gas combustion turbines (CTs).²⁸

<u>All</u> of the proposed gas generation raises <u>stranded asset risk</u>, but the utilities fail to mention that fact. This is a glaring omission as it is the judgment of Florida's largest utility FPL that in four years, 2020, gas peakers will be obsolete compared to energy storage and renewables.²⁹ It is even more troubling then that the utilities never present any options analyses for the proposed gas peakers. Nor even the basic data to allow for such a

²⁵ FRCC, 2016 Presentation, at 22.

²⁶ Id.

²⁴ See the detailed briefing by Public Counsel, filed July 15, 2015, in Docket No. 160096-EI, <u>Joint petition for</u> approval of modifications to risk management plans by DEF, FPL, Gulf and TECO; See also joint petition filed by Public Council, filed Dec 9., 2015, in Docket No. 150196-EI, <u>In re: Petition for determination of</u> need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company, available at <u>https://goo.gl/wBgl2S</u>.

²⁷ Tampa Electric Company's 2016 Ten-Year Site Plan (hereinafter "TECO 2016 TYSP") (planning to add 180 MW CT in 2019), *available at* https://goo.gl/zGh1Id.

²⁸ OUC and FPL propose gas combined cycle generation (CCs) with 2021 and 2024 in-service dates respectively. Like CTs, the CCs involve massive costs and risks, and the utilities can only add them in large, inflexible increments. Thus, beyond the marginal efficiency improvement of CCs over CTs, our discussion of the CTs applies equally to the CCs.

²⁹ NextEra on Storage: 'Post 2020, There May Never Be Another Peaker Built in the US,' Sept. 30, 2015, GreenTech Media [hereainafter "NextEra on Storage"], https://goo.gl/rQDK0H (referring to judgment of team including FPL executives).

comparison. In response to Staff data requests, for instance, the utilities omitted the inputs and workbooks that would allow independent verification of their summary comparisons between two gas generation options, discussed in Section II.B.1 above, and provided virtually no data on other, non-gas options, as discussed further below in Section II.B.3.

As the Commission maintains separate dockets on the operation and maintenance costs and risks of gas generation, it knows how astronomically high those costs and risks have proven to be. With gas prices at all-time lows—levels so low they are widely expected to only go up from here—Floridians have already lost <u>billions of dollars</u> on risk hedging programs.³⁰ Still, the hedging programs themselves are mere half-measures against the price and supply risks of Florida's reliance on natural gas imports—and useless against stranded asset risk. The FPL rate case underscores this.³¹ FPL supported its request for a \$1.3 billion annual rate increase and a 100 basis point return on equity increase with sworn testimony on all the costs and risks associated with managing its out-sized gas generation fleet.

Adding more gas generation is thus indefensible because it would exacerbate the burden on customers who essentially bear all the costs and risks. This includes the tremendous capital outlays required at the outset to add gas generation (recovered through base rates), and the tremendous operations and maintenance, including hedging expenses, over the 30 or more years these plants are supposed to be in service (recovered through separate clauses).

3. Renewables and energy efficiency are abundantly available to meet peak demand, and they can achieve deep cost-savings—unlike gas generation—through their flexible and diverse applications across the electric grid's generation, transmission, and distribution functions.

For alternatives to meet peak demand, such as renewables and energy efficiency, the market is better than ever. Yet the utilities only propose relatively modest amounts of solar, and even less amounts of other alternatives, despite these technologies' maturity, competitiveness, and widespread adoption in neighboring states. Moreover, these technologies can achieve deep cost-savings—unlike gas generation—through their flexible and diverse applications to the grid's electric generation, transmission, and distribution functions. As we discuss below, this is borne out by RFPs and integrated resource plans (IRPs) across our region and the country. We also discuss how the IOUs' refusal to conduct RFPs for renewables makes them particularly unprepared to deliver least-cost service.

³⁰ See the detailed briefing by Public Counsel, filed July 15, 2015, in Docket No. 160096-EI, <u>Joint petition for</u> approval of modifications to risk management plans by DEF, FPL, Gulf and Tampa Electric Company.

³¹ FPSC Docket No. 160021.

a. Solar

Solar generation technologies, especially solar photovoltaics (PV) can meet peak demand³² and achieve deep cost savings as a hedge against natural gas price volatility.³³ Solar PV is also a flexible resource, precisely what Florida needs as discussed in Section II.B.1 above. With an abundant solar resource—consistently ranked third best in the country for solar generation potential³⁴—and ample support for developing it in Florida Statutes, discussed above in Section I.B, the utilities should be planning to "make Florida a leader in [this] new and innovative technolog[y]."³⁵

Florida's tremendous solar potential, however, remains largely untapped because, in essence, the IOUs—with their overwhelming control of the state's energy market—sit on the tap. FPL is the sitter in chief. Florida's largest utility has not issued an RFP for renewable energy since 2007 and 2008, and never explains this omission, even though FPL acknowledges the cost of solar PV has since "plunged."³⁶ Likewise, DEF, the second largest utility, admits that it received "436 inquiries" from third parties interested in developing instate renewables.³⁷ As Sierra Club has consistently highlighted, and as the Southern Alliance for Clean Energy (SACE) comments discuss in more detail, a disturbing lack of transparency shrouds such inquiries. This includes the modest solar power purchase agreements (PPAs) that DEF has negotiated to date. DEF refuses to disclose details, even such basic ones as the in-service, start, and end dates of the PPAs.³⁸ Gulf Power Company (Gulf) and Tampa Electric Company (TECO) are no better.³⁹

³⁴ See, e.g., AEE, Advanced Energy in Florida (Jun. 11, 2015), available at https://goo.gl/BBL5M4.

³⁵ Section 366.91(1), F.S.

³⁷ DEF response to Staff data request no. 35.

³² See, e.g., FPL 2016 TYSP, at 49-50 (crediting solar PV with 52% nameplate capacity at summer peak).

³³ Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (Sept. 2015) at ii ("At these low levels – which appear to be robust, given the strong response to recent utility solicitations – PV compares favorably to just the fuel costs (i.e., ignoring fixed capital costs) of natural gas-fired generation, and can therefore potentially serve as a [']fuel saver['] alongside existing gas-fired generation (and can also provide a hedge against possible future increases in fuel prices).") (hereinafter "Utility-Scale Solar 2014"), *available at* https://goo.gl/0L2dDOU.

³⁶ NextEra on Storage, https://goo.gl/eIVoSL.

³⁸ DEF response to Staff data request no. 28 (stating "n/a" or "TBD" for in-service, start, and end dates).

³⁹ See generally Gulf Power Company's 2016 Ten-Year Site Plan (hereinafter "Gulf 2016 TYSP"), available at https://goo.gl/PE1qbW; Gulf 2016 TYSP Workshop Presentation, available at https://goo.gl/GH9rME; TECO 2016 TYSP; TECO 2016 TYSP Workshop Presentation, available at https://goo.gl/rQNeYF.

Collectively, the IOUs plan to add in <u>ten years</u> as much solar generation as Gulf's sister subsidiary, Georgia Power, will add by <u>next year</u>—more than a gigawatt.⁴⁰ Moreover, through additional RFPs, Georgia Power plans to <u>double</u> its installed capacity again <u>in five years</u> with more solar PV, battery storage, and other renewables.⁴¹ Georgia Power is hardly alone. In 2015, 100% of Alabama Power's new generation came from solar, and that utility just gained approval to issue RFPs for 500 MW more.⁴² In fact, RFPs in <u>every</u> single state in the Southeast have returned abundant, cost-effective solar PV bids.⁴³ These are widely reported precedents, which reputable entities such as the U.S. Department of Energy also verify and publish in market reports.⁴⁴ Yet the IOUs never mention them; much less reconcile their refusal to issue RFPs with the relatively modest amounts of solar they propose to build themselves.

Indeed, the utilities present no data or analyses whatsoever to justify the relatively modest amount of solar generation they propose. The RFPs of other Florida utilities, however, confirm there is no shortage of cost-effective solar PV in Florida.⁴⁵ As we highlighted last year, on a per customer basis these utilities have already installed far more solar capacity than the IOUs.⁴⁶

The IOUs' proposals to add solar are also mere placeholders. Unlike the solar PV contracts that other utilities are negotiating with third parties, the IOUs have identified no particular process to set the terms of the solar they would build, such as the timing, sizing, siting, sourcing of inputs, and the costs. This gives the Commission—and the public—no reassurance whatsoever that the IOU investments in solar generation will in fact be optimally timed, sized, sited, etc. to achieve least-cost service. ⁴⁷

⁴⁴ See, e.g., Utility-Scale Solar 2014, at 37; See also Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States (2016), *available at* https://goo.gl/SpUJY2.

⁴⁵ See Exhibit B: Florida RFPs for solar.

⁴⁶ See Sierra Club 2015 Comments, at 12.

⁴⁷ Sierra Club supports SACE's comments and shares SACE's concern that, beyond ten-year site plan reviews, the Commission may not get another opportunity to conduct fact-finding until after the utilities have already built whatever solar generation they unilaterally selected.

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⁴⁰ Georgia Power, Utility-Scale RFP Program, *available at* https://goo.gl/yEKHAu.

⁴¹ Georgia Power 2016 Integrated Resource Plan, at 10-101, available at https://goo.gl/CdMFiZ.

⁴² See Top 10 Solar States (2015), https://goo.gl/F3jIVu; See also Alabama Power's plan for 500 MW of renewables approved by regulators, Utility Dive, Sept. 3, 2015, https://goo.gl/uf5Ffm.

⁴³ See Exhibit A: Southeast RFPs for renewables.

b. Energy storage

Energy storage is another competitive alternative to gas generation. Tellingly, the states that already use energy storage want to add more of it. This includes Alabama,⁴⁸ Georgia,⁴⁹ West Virginia,⁵⁰ Tennessee,⁵¹ and California.⁵² Other states with energy storage market studies, such as Texas and Massachusetts, also report that this technology can provide immense improvements to the electric grid—and deep cost-savings relative to the status quo.

In contrast, there is a glaring omission of energy storage from the Florida utility plans. At the planning workshop, DEF explained that it lumps energy storage with offshore wind,⁵³ but that technology came online for the first time this summer.⁵⁴ Energy storage projects in contrast have been operational for decades. The first advanced compressed air energy storage (CAES) plant came online in 1978, and the first one in the US, in 1991, in

⁵⁰ In West Virginia, AES Energy Storage installed the Laurel Mountain Energy Storage Project at the Laurel Mountain wind plant, which delivers 32 MW of regulation and wind smoothing. The World's Largest Lithium-Ion Battery Farm Comes Online, Forbes, Oct. 27, 2011, https://goo.gl/L5g8K9.

⁵¹ The Tennessee Valley Authority (TVA) operates the Raccoon Mountain Pumped-Storage Plant in Marion County, Tennessee. With capacity of 1,616 MW, it is TVA's largest hydroelectric facility and "provides critical flexibility." 2015 Tennessee Valley Authority Integrated Resource Plan (hereinafter "2015 TVA IRP"), at 40, *available at* https://goo.gl/GiURX3.

⁵² World's Largest Storage Battery Will Power Los Angeles, Scientific American, July 7. 2016, https://goo.gl/cvGXzD; CNBC, Tesla tackles California energy woes with massive energy-storage deal, Sept. 16, 2016, https://goo.gl/z1YELb; California Dreaming: 5,000MW of Applications for 74MW of Energy Storage at PG&E, GreenTech Media, May 28, 2015, https://goo.gl/nuZRT4.

⁵³ Duke Energy has relegated energy storage has into a third category of "Emerging Technologies," along with offshore wind technologies. Duke Energy, A Brief Overview of DEF Planning. Duke Presentation, given at the Sept. 14, 2016 Ten-Year Site Plan Workshop, *available at* https://goo.gl/STKM0q.

⁴⁸ As noted above, Alabama Power recently gained approval to issue additional RFPs for renewables. The company built the country's first compressed air energy storage CAES plant, 110-MW McIntosh plant, in 1991. PowerSouth Energy Cooperative, https://goo.gl/idGTAz. ("The unit captures off-peak energy at night, when utility system demand and costs are lowest. [...] PowerSouth uses the stored energy during intermediate and peak energy demand periods to generate electricity.").

⁴⁹ As of September of 2015, Georgia has the largest Southern Company battery storage research project, which is testing a 1 MW/2 MWh lithium-ion battery storage system at a solar facility. Southern Company: Cedartown Battery Energy Storage Project, Sept. 17, 2015, https://goo.gl/MvLO7a; Southern Company also has a partnership with Tesla to test energy-storage products for commercial customers. Southern Co. goes all in on solar, storage, smart homes, EnergyWire, May 28, 2015, https://goo.gl/LjxEwD.

⁵⁴ Offshore Wind Arrives in America, Energy.gov, Sept. 9, 2016, https://goo.gl/sqjxpr.

⁴²

Alabama.⁵⁵ Now, as utilities across the country are rapidly procuring storage, Florida utilities are behind, without even a plan to explore procurements of their own.

As noted above, FPL itself acknowledges that energy storage is a competitive alternative to peakers. Market studies commissioned by state energy regulators and by other utilities agree: energy storage investments can save <u>hundreds of millions, if not billions</u> of dollars.⁵⁶ These projected savings stem from the wide-ranging applications of this technology, spanning electric generation (on and off peak), transmission, and distribution.

Peak generation is of course the most expensive generation, and storage allows utilities to reduce or avoid that generation altogether by redeploying surplus energy from lower cost, off-peak hours. A 2016 report by the state of Massachusetts concluded that this application alone could save customers in that state <u>more than a billion dollars</u>. Other studies document the cost savings from energy storage's ability to reduce transmission and distribution-related maintenance, as well as defer and even avoid huge capital expenditures.⁵⁷ In 2014, Texas utility, Oncor, announced it would seek approval to build <u>5,000 MW of energy storage</u> citing over <u>\$625 million of projected customer savings</u>.⁵⁸

Storage can also reduce risk by providing both flexibility and reliability. Energy storage is in fact highly accommodating with sizing, siting, permitting, and construction time. Because this technology does not produce direct air emissions, or have large land requirements, the permitting and siting processes are far easier.⁵⁹ Because individual storage systems are modular, one system can consist of many modules operating simultaneously, and can take on additional modules incrementally, so the system will not fail from the breakdown of one module.⁶⁰ Additionally, several types of advanced storage technologies are commercially viable, ⁶¹ including batteries, compressed air energy storage, liquid air energy storage, pumped hydroelectric storage, and flywheels.⁶² They are also readily available. A

⁵⁷ Id. at 86-89.

⁵⁵ PowerSouth Energy Cooperative, https://goo.gl/idGTAz.

⁵⁶ A 2016 report by the state of Massachusetts concludes that 600 megawatts of storage capacity installed by 2025 would save ratepayers \$800 million in system costs. Massachusetts Energy Storage Initiative Study (2016), at xvi-xvii, *available at* https://goo.gl/D3zviD.

 ⁵⁸ The Value of Distributed Electricity Storage in Texas Proposed Policy for Enabling Grid-Integrated Storage Investments (2014), at 14, *available at* https://goo.gl/fv2mYF.
 ⁵⁹ Massachusetts Energy Storage Initiative Study, at 9.

⁶⁰ Massachusetts Energy Storage Initiative Study, at 10.

⁶¹ This is evidenced by their widespread use in competitive markets without subsidies. Id. at 2.

⁶² Energy Storage Technologies, https://goo.gl/5vcJTb.

2016 study found utilities could procure these advanced technologies within months—four to six times faster than conventional technologies.⁶³

The value of energy storage is also apparent in California's use of it to solve the emergency that resulted from the massive gas facility failure at Aliso Canyon. That failure put the entire region at high risk of far-reaching power outages. State regulators directed utilities to speed up the deployment of large-scale, grid-connected storage. As of August, California utilities have proposed three large-scale battery installations⁶⁴—one with an inservice date just <u>five months</u> after it was proposed.⁶⁵

c. Energy efficiency

Energy efficiency is the lowest-cost energy resource available,⁶⁶ and is essential to deliver least-cost electric service. More specifically, the wide-ranging technologies labeled as energy efficiency are part of the demand-side management that Florida needs to keep demand down and electric bills low, as noted in Section II.B.1 above. Yet the utilities continue their practice of ignoring any incremental energy efficiency additions beyond the levels set by the Commission based on information three or more years old.⁶⁷ This cannot be squared with the more recent market assessments, including those in other Southeast states, consistently showing that energy efficiency is not only cost-effective, but a critical resource to meet peak demand,⁶⁸ reduce risk, and save customers money.⁶⁹

⁶⁵ As Aliso Canyon Gas Shortage Looms, Southern California Looks to Energy Storage, Greentech Media, Jun. 02, 2016, https://goo.gl/JrI0O4; *See also* California Utilities Are Fast-Tracking Battery Projects to Manage Aliso Canyon Shortfall, GreenTech Media, Aug. 18, 2016, https://goo.gl/9XyYx1. (stating that the projects must be grid-ready by year's end, in SCE's case, or by Jan. 31, 2017, in SDG&E's case.).

⁶⁶ SEE, Guide For States: Energy Efficiency As A Least-Cost Strategy To Reduce Greenhouse Gases And Air Pollution, And Meet Energy Needs In The Power Sector (2016), *available at* https://goo.gl/ZtQ7pc; *See also* ClimateWorks & Fraunhofer ISI, How Energy Efficiency Cuts Costs for a 2°C Future (2015), *available at* https://goo.gl/fjf0xR; *See also* The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (2014), *available at* https://goo.gl/GPYhzU.

⁶⁷ Here, "utilities" refers to the utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA). The other Florida utilities also have an obligation to provide least-cost service and to that end should develop and disclose robust options analyses focusing on energy efficiency.

⁶⁸ At very low cost and risk, efficiency offers flexibility in meeting peak demand. Florida utilities can quickly ramp up efficiency to meet demand growth and thereby reduce or entirely avoid costly infrastructure improvements and expansion. RAP, Recognizing the Full Value of Energy Efficiency (What's Under the Feel-

⁶³ Id. at 10.

⁶⁴ They proposed two 20 MW (80 MWh) facilities from SCE and a 37.5 MW (150 MWh) project from SDG&E. 'Eyes wide open': Despite climate risks, utilities bet big on natural gas, Utility Dive, Sept. 27, 2016, https://goo.gl/697hYh.

Energy efficiency programs are inherently less risky since they consist of many discrete resources that will not fail all at once.⁷⁰ Additionally, efficiency increases system reliability by reducing the stress on it. Many utilities give energy efficiency resources a risk credit, meaning the risk reduction effects of implementing efficiency reduced the cost of energy efficiency.⁷¹ Thus, efficiency is a highly predictable and reliable cost-effective resource that enables the utility system to avoid the risk of surpluses, shortages, and periodic outages.

The utilities' refusal to consider incremental energy efficiency additions is even more alarming given the highly publicized, rapid changes in the market, and the <u>billions of dollars</u> that other utilities reported saving in recent years from geographically targeted energy efficiency programs, especially those that defer or avoid large transmission and distribution expenditures.⁷² This Commission itself stated that, "at any time," it is ready to "reexamine and then adopt new [energy efficiency/demand-side management] goals or changes to those goals." ⁷³ It is the responsibility of the utilities to develop data and analysis to allow the Commission to do so.

Indeed, if the utilities and the Commission are serious about closing the gap that minority and low-income households spend on energy, then they will rapidly develop plans to increase investment in energy efficiency, as leading energy efficiency experts have recommended.⁷⁴

⁶⁹ Because efficiency reduces all pollutants, it can also save ratepayers money by satisfying environmental regulations without building new power plants, which require huge, inflexible capital outlays.

⁷⁰ 2013 RAP Energy Efficiency Report, at 41.

⁷¹ The 2013 PacifiCorp IRP and the Northwest Power Council both give energy efficiency resources risk credit. ACEEE Comments on 2015 Tennessee Valley Authority Draft Integrated Resource Plan, at 3.

⁷² For instance, in 2011, Consolidated Edison estimated that including the effects of geographically-targeted efficiency programs in its 10-year forecast reduced costs by over \$1 billion. Additionally, since 2012, ISO New England identified over \$400 million in deferred transmission investments due to efficiency. NEEP Northeast Energy Efficiency Partnerships: Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically (2015), at 12 available at https://goo.gl/AXRf3m.

⁷³ FPSC Transcript Document No. 06614-14, at 21, Order No. PSC-14-0696-FOF-EU, filed Dec. 5, 2014, in Docket No. 130205-EI.

⁷⁴ ACEE, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities, Apr. 20, 2016, at 3-4. (For African-American, Latino, and renting households, 42%, 68%, and 97% of their excess energy burdens, respectively, could be eliminated by raising household efficiency to the median.).

Good Frosting of the World's Most Valuable Layer Cake of Benefits) (2013) (hereinafter "2013 RAP Energy Efficiency Report"), at 41, *available at* https://goo.gl/APjr2s.

C. Rather than minimize cost of service to customers, the plans pave the way for windfalls for the IOUs/their affiliates at the expense of the captive customer base; it is imperative for the Commission to intervene and reject the plans.

As discussed above, the plans are in no way least-cost from an electric utility customer perspective. Others, however, certainly profit from these gas-laden proposals. The most obvious profiteers are the shareholders of the IOUs/their affiliates—together they are heavily investing in gas generation and infrastructure, such as inter-state pipelines. This gives the IOUs a perverse incentive to increase their reliance on and subsidize the inefficient production and distribution of natural gas as they pass increases in fuel costs directly to customers.

In his testimony before the Senate Energy and Natural Resources Committee, Jonathan Peress highlights "a <u>disturbing trend</u> of utilities pursuing a capacity expansion strategy by imposing transportation contract costs on state-regulated retail utility ratepayers so that affiliates of those same utilities can earn shareholder returns as pipeline developers. . . . Thus ratepayer costs which may not be justified by ratepayer demand are being converted into shareholder return."⁷⁵ Mr. Peress further explains, "<u>the effect of these affiliate</u> <u>transactions</u>, whereby utilities commit their captive customers to pay for pipelines being developed by the same corporate group, <u>is that customers are saddled with risky 20 year</u> <u>financial obligations to provide nearly risk free shareholder returns of 14% per year or</u> <u>more</u>."⁷⁶

Ultimately, Mr. Peress warns, affiliate transactions can hurt not only customers but also market participants. In Florida, this includes business, large or small, that lose opportunities to provide efficient solutions for electric service due to the control that the IOUs/their affiliates exert over the state's energy market. This is the rub, for instance, in FPL and DEF's decision to import more gas through the Southeast Market Pipeline Project instead of less costly, Florida-made solutions for them to provide an adequate and reliable supply of electricity.

In recent years, mergers between the IOUs and pipeline companies have proliferated⁷⁷—growing the potential for the fallout described by Mr. Peress. Again, the Southeast Market Pipeline Project ⁷⁸ is case in point: FPL and DEF back this pipeline even

⁷⁵ Jonathan Peress, Testimony Before the Senate Energy and Natural Resources Committee (June 14, 2016), at 5, https://goo.gl/rPoudE.

⁷⁶ Id.

⁷⁷ See Exhibit C: Mergers between pipeline companies and IOUs/their affiliates.

⁷⁸ Sabal Trail is part of multiple pipeline expansions and a joint venture of DEF's parent, Duke Energy Corporation, and FPL's parent, NextEra.

⁴⁶

though it would more than double the amount of natural gas that FPL and Duke themselves project needing.⁷⁹

Coupled with the utilities' hedging programs, the recent mergers and affiliate transactions raise an acute threat of improper subsidization of pipeline companies by Florida electric utility customers.⁸⁰ Between 2002 and 2015, the four IOUs saddled their customers with more than a <u>\$6 billion</u> bill for fuel costs higher than market price.⁸¹ Public Counsel has protested this, citing the IOUs' own estimates of another \$559 million in losses-borne again by customers.⁸² If the Commission were to allow the utilities, now merged with pipeline companies, to increase their gas generation, customer bill could soar even higher.

As the Antitrust Division of the United States Department of Justice recognizes, this type of vertical integration "may be used by monopoly public utilities subject to rate regulation as a tool for circumventing that regulation. <u>The clearest example is the acquisition by a regulated utility of a supplier of its fixed or variable inputs</u>. After the merger, the utility would be selling to itself and might be able arbitrarily to inflate the prices of internal transactions. Regulators may have great difficulty in policing these practices, particularly if there is no independent market for the product (or service) purchased from the affiliate."⁸³ Vertical integration of the retail distribution and generation markets plus financial hedging of natural gas thus presents a clear conflict of interest whereby self-dealing practices can rampantly exploit the captive customer base.

To protect customers and diverse businesses in Florida, it is imperative for the Commission to reject the plans, and put all the utilities on a path to reduce, not increase, Florida's generation.

⁷⁹ FPL admitted that it would only require 400,000 Dth/day by 2017 and 600,000 Dth/day by 2020, yet it moved forward with the construction of Sabal Trail, which will ship double that amount—800,000 Dth/day by 2017 and 1.1 billion Dth/day by 2020. *Compare* Testimony of Heather C. Stubblefield on behalf of the Florida Power & Light Co., FPSC Docket No. 130198, July 26, 2013 at 9:10-13, (testifying that FPL requested these amounts "based on FPL's analyses of its future gas transportation requirements"); Application by Florida Southeast Connection, LLC ("FSC") to FERC for a Certificate of Public Convenience and Necessity and for Related Authorizations, Sept, 26, 2014 at 2, (stating amount that Sabal Trail will ship).

⁸⁰ For example, the \$3 billion Atlantic Sunrise gas pipeline expansion proposal pending before the Federal Energy Regulatory Commission (Docket No. CP15-138) would connect to delivery points in Florida, and FPL and DEF have intervened in the FERC proceeding, indicating they have a material interest in this pipeline.

⁸¹ Office of Public Counsel Protest, Document No. 05102-16, at 2, filed July 15, 2016, in Docket No. 160096-EI (hereinafter "Public Counsel Protest of Hedging Losses").

⁸² Public Counsel Protest of Hedging Losses, at 2.

⁸³ United States Department of Justice, Antitrust Division, Non-Horizontal Merger Guidelines § 4.3 Evasion of Rate Regulation, *available at* https://goo.gl/9xw0QB.

D. The utilities acknowledge they can wait many months, even years before committing resources to add any gas generation, so they have time to pursue alternatives instead.

The utilities cite no reason to move forward now with their proposals to add gas generation.⁸⁴ Indeed, the purpose of this generation is mainly to meet projected growth in peak demand.⁸⁵ We reiterate that this growth may never materialize. Even if it did, the utilities acknowledge they can wait many months, even years, before committing any resources to adding gas generation.⁸⁶ More specifically, November 2017 is the earliest "drop dead" date (for a 200 MW CT with a May 2020 in-service date), and that could be pushed back by six months.⁸⁷ The utilities thus have ample time to complete the missing RFPs and options analyses and revise their plans to pursue cost-effective alternatives instead.

E. Florida's high-cost, high-risk coal generation reinforces the need for revised plans including the chronically missing options analyses.

While the utilities are not proposing any new coal generation, their existing coal burning generation undermines their ability to provide least-cost service. Burning coal to generate electricity lost whatever economic edge it once had, as evidenced by the overwhelming national coal divestment trend.⁸⁸ To be sure, coal is a terrible deal: Not only is burning coal one of the priciest⁸⁹ and most polluting⁹⁰ ways to generate electricity, importing coal from out of state also stunts local economic growth.⁹¹

With no shortage of low-cost, low-risk alternatives in the market, all remaining coal owners and operators owe their regulators robust options analyses focusing on options for transitioning to the alternatives as soon as practicable. The regulators, in turn, are wise to

⁸⁶ See response to Staff data request no. 40; See also 2016 TYSP Schedule 9s.

⁸⁷ TECO 2016 TYSP; See also TECO response to Staff data request no. 40.

⁸⁸ See, e.g., EIA, 'Coal made up more than 80% of retired electricity generating capacity in 2015' (Mar. 8, 2016) available at https://goo.gl/b0xcAq; See also Sierra Club, Open letter to coal industry: United States and the world are moving away from coal, toward clean energy (Apr. 21. 2016) available at http://goo.gl/kE94J6.

⁸⁹ See 2016 TYSP Comments, supra n. 3 (citing sources on how coal generation costs compare to alternatives).

⁹⁰ See Mother Jones, 'Environmentalists Hate Fracking. Are They Right?' (May 11, 2016) available at http://goo.gl/dGtFju.

⁹¹ See Union of Concerned Scientists, Burning Coal, Burning Cash: 2014 Update; Fact Sheet: Florida's Dependence on Imported Coal (Jan. 2014) *available at* http://goo.gl/Y3Yw21.

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⁸⁴ Staff data request no. 42.

⁸⁵ As noted above, OUC and FPL propose adding CCs as well.

disallow further expenditures on uncompetitive coal generation, as the Georgia Public Service Commission just did in the integrated resource planning proceeding it recently concluded for that state's largest electric utility Georgia Power.⁹²

Yet in Florida, the utilities have continued their practice of presenting no options analyses regarding their existing coal generation. This is a grave omission, as we have consistently warned, because the utilities' own, incomplete regulatory compliance cost estimates for this generation range in the <u>hundreds of millions to billions of dollars</u>.⁹³ Moreover, when Staff asked for up-to-date information—underscoring the dearth of information in the plans—the utilities indicated that their analyses are still incomplete, and they failed to provide any estimate whatsoever for several <u>existing</u> regulations.⁹⁴

One glaring omission concerns the Effluent Limitations Guidelines (ELGs), the new U.S. Environmental Protection Agency rule to protect our waters from the toxic pollutants in the discharge of coal generators. The ELGs became effective on January 4, 2016, and the default deadline is November 2018. As it took EPA decades to issue this rule, utilities have long anticipated and planned for it.⁹⁵ Indeed, the IOUs must report their compliance estimates under federal financial disclosure rules, and have in fact reported such estimates for ELGs, which are as high as \$50 million for just one of a dozen Florida coal plants.⁹⁶

With such massive costs looming over them, it is unacceptable for the utilities to continue to delay studying their options to transition to non-fossil generation.⁹⁷ Indeed, as we highlighted last year, Lakeland Electric stands out as the one Florida utility that already commissioned such a study. Lakeland compared several retrofit and retirement scenarios for its aging coal plant, showing that the analysis itself is eminently doable.⁹⁸ Predictably, Lakeland's conclusion, which the utility is now refining with further studies, is that

⁹² See Exhibit D – Georgia Power IRP Stipulation, at 3 ("minimiz[ing] all capital expenditures" on two large coal generation facilities); See also GPSC Docket No. 40161, Direct Testimony of T. Newsome and P. Hayet, at 7 and 51 (Commission staff expert recommending "all capital investment" on costly coal plants be "minimize[d].") (May 6, 2016) available at http://goo.gl/SF9rba.

⁹³ See Sierra Club 2015 Comments, at 7.

⁹⁴ See generally Utility responses to Staff data requests nos. 50-62.

⁹⁵ See Exhibit E – Sierra Club Comments to Florida Dep't of Environmental Protection (FDEP) re: ELGs.

⁹⁶ See Exhibit F – Sierra Club Comments to FDEP re: Crystal River Energy Center.

⁹⁷ To be clear, Sierra Club does not support new nuclear generation as it extremely high cost and high risk and thus a nonsensical choice given all of the better alternatives available in the market.

⁹⁸ nFront Consulting LLC, "Strategic Resource Plan, Lakeland Electric," (Mar. 2015), *available at* http://goo.gl/B2BmRK.

renewables and energy efficiency will meet its load growth over the next 20 years more costeffectively than all three fossil fuel expansion scenarios studied.⁹⁹

III. The Commission should require the utilities to file revised plans as soon as practicable.

For all the foregoing reasons, the Commission should reject the plans and require all the utilities to file revised plans as soon as practicable, including the chronically missing options analyses. The IOUs should file revised plans no later April 1, 2017, the annual deadline for plan revisions, to minimize the fallout from their conflict-ridden plans.

Thank you for your consideration.

Respectfully submitted,

/s/ Diana A. Csank

Diana A. Csank Sierra Club Staff Attorney 50 F Street NW, Eighth Floor Washington, DC 20001 Phone: 202-548-4595 E-mail: Diana.Csank@sierraclub.org

Jean Zhuang Sierra Club Law Fellow

⁹⁹ Id. at 3-13, 3-24.
EXHIBIT A

Exhibit A: RFPs for Renewables in the Southeast

The following is an illustrative list of RFPs for renewables in the Southeast.

<u>Alabama</u>

- The Alabama Public Service Commission (PSC) approved a proposal from Southern Company subsidiary Alabama Power, the state's dominant electricity provider, to procure up to 500 MW of renewable energy from 80 MW or smaller facilities. The utility's proposal cited both a need for renewables to meet Clean Power Plan emissions reductions requirements and customer demand. The utility's request for proposals (RFP) requires renewables projects to be priced below what it would expect to pay for other generation sources, unless the off-taker agrees to pay the difference.¹
- On September 27, 2016, Alabama Power issued a request for proposals (RFP) for renewable energy resources. For a proposed project to be considered under this RFP, the generation resource must be either a renewable resource, as identified in Section 40-18-1(30), Code of Alabama (1975), or an environmentally specialized generating resource. Eligible projects include solar, wind, geothermal, tidal or ocean current, low-impact hydro and biomass.²

Georgia

Georgia Power Company's 2015/2016 Advanced Solar Initiative Distributive Generation Program sought proposals and applications for solar photovoltaic generation. The Georgia public Service Commission has given approval to Georgia Power Co., a unit of Southern Co., to release a request for proposal for 495 MW of new solar power generation. The commission approved 425 MW of the requested amount on July 12, 2013 as part of the 2013 Georgia Power Co. Integrated Resource Plan and 70 MW as part of the utility's Advanced Solar Initiative November 20, 2012.³

Kentucky

• East Kentucky Power Cooperative RFP sought to obtain up to 300 MW of generation, including renewable resources with a capacity of 5 MW or larger. EKPC will retain all environmental attributes associated with the renewable resources.⁴ (Closed August 30, 2012)

<u>Mississippi</u>

• The South Mississippi Electric Power Association RFP sought capacity and/or related energy from wind resources with up to 250 MW of nameplate capacity.⁵ (Closed August 31, 2015)

Tennessee

• State of Tennessee RFP sought proposals for design, delivery, installation, operation and maintenance of renewable energy systems using solar photovoltaic electric generating technologies to supply energy to the State at multiple sites.⁶ (Closed August 9, 2016).

¹ https://goo.gl/dnY5Ea.

² https://goo.gl/XXCQAh.

³ https://goo.gl/FkAz21.

⁴ https://goo.gl/7GhgcP.

⁵ https://goo.gl/OS1kKz.

⁶ https://goo.gl/CsM2QY.

Virginia

- EPB RFP sought proposals from qualified contractors for the labor and materials needed to build the first of two community solar power generation facilities under its Solar Share pilot project. The first project will be built in the Bakewell community of northern Hamilton County and the second one is planned near existing EPB facilities in Chattanooga. The two projects will provide a combined 1.35 megawatt generation capacity.⁷ (Closed May 15, 2016)
- The Council of Independent Colleges in Virginia (CICV) RFP sought proposals to construct and finance up to 37.8 MW solar photovoltaics (PV) systems at the campuses of some of its member colleges. The project is supported by the U.S. Department of Energy's SunShot Initiative. Bidders shall propose the construction of different types of PV systems under various financing mechanisms that creates net cost savings to participating colleges.⁸ (Closed January 22, 2016)
- Solarize Harrisonburg RFP sought a single price/kW installed for a group of residential homeowners in Harrisonburg, Virginia. This price will be offered to all homeowners participating in the group. The PV projects are to be installed on the roofs of each of the properties and will be owned by the individual property owners.⁹ (Closed September 11, 2014)
- Appalachian Power Company RFP sought proposals to solicit and subsequently pre-qualify companies who have an interest in participating in the company's RFP for obtaining up to 10 MW (AC) of ground-mounted solar energy resources via either an asset purchase with 100% ownership or 20-year PPA. Proposed projects must be located within Virginia, be interconnected to the PJM Regional Transmission Operator or Appalachian Power's distribution system, and have a minimum nameplate rating of 5 MW (AC).¹⁰ (Closed February 5, 2016)

North Carolina

- The City of Raleigh RFP sought proposals from qualified solar energy developers to own, install, operate, and maintain solar systems on approximately 53 acres of city-owned land near the Neuse River Resource Recovery Facility.¹¹ (Closed January 8, 2016)
- NC GreenPower RFP sought proposals for up to 60,000 MWh of renewable energy through a purchase with either a one- or two-year term. The potential generator of renewable energy will be required to enter into a Power Purchase Agreement with a North Carolina electric utility and the generated power will be delivered to North Carolina's electrical supply.¹² (Closed January 6, 2016)
- NC GreenPower RFP sought proposals for up to 40,000,000 kWh of Renewable Energy Certificates (RECs) generated in North Carolina through one- or two-year terms from qualifying renewable energy projects.¹³ (Closed November 25, 2014)

South Carolina

• Duke Energy Carolinas and Duke Energy Progress RFP sought approximately 40 MW and 13 MW of eligible photovoltaic generation capacity and all associated renewable attributes located in and

⁷ https://goo.gl/y0a1sk.

⁸ https://goo.gl/Ay3DUh.

⁹ https://goo.gl/mWiAcl.

¹⁰ https://goo.gl/vNNFbr.

¹¹ https://goo.gl/1fZ1sQ.

¹² https://goo.gl/Yrjj3M.

¹³ https://goo.gl/2iZOSd.

directly interconnected to its retail service areas in South Carolina via a combination of Power Purchase Agreements and turnkey proposals with engineering, procurement and construction agreements in the form of Design-Build-Transfer Asset Purchase proposals.¹⁴ (Closed October 27, 2015)

- Duke Energy Carolinas and Duke Energy Progress RFP sought approximately 4 MW and 1 MW of eligible photovoltaic generation capacity and all associated renewable attributes located in and directly interconnected to its retail service areas in South Carolina via a combination of Power Purchase Agreements and turnkey proposals with engineering, procurement and construction agreements in the form of Design-Build-Transfer Asset Purchase proposals. Proposals must comply with Duke Energy's "Shared Solar Program" requirements under the South Carolina Distributed Energy Resource Program Act and be in service by December 31, 2016.¹⁵ (Closed October 27, 2015)
- South Carolina Electric & Gas Company RFP seeking bidders to provide solar power to the utility through purchased power agreements. SCE&G intends to work with solar developers to locate the solar farms on company-owned property in North Charleston (up to 500 kW) and Cayce (up to 4 MW).¹⁶ (Closed October 3, 2014)

<u>Louisiana</u>

- State of Louisiana Department of Education RFP seeking bids for the installation of solar panels at Andrew Jackson Elementary School located in New Orleans, LA.¹⁷ (Closed June 26, 2012)
- AEP Southwestern Electric Power Company (SWEPCO) RFP seeking long-term renewable energy to help fulfill energy-supply requirements for its customers. The request was issued as part of the Louisiana Public Service Commission's Renewable Energy Pilot Program. Proposals for approximately 31 megawatts of new renewable-energy resources deliverable to the Southwest Power Pool (SPP). Resources must be able to begin operating by Dec. 31, 2014, and have a minimum 10-year PPA.¹⁸ (Closed June 15, 2011)

Multiple States in the Southeast Involved

- Southern Alliance for Clean Energy RFP sought a contractor to perform a transmission analysis for gigawatt-scale offshore wind energy off North Carolina, South Carolina and Georgia. (Phase 2C -Offshore Wind Energy Transmission Study).¹⁹ (Closed February 16, 2011)
- Appalachian Power RFP sought up to 150 megawatts of wind power. Proposals should allow Appalachian Power to own one or more wind projects or purchase the output from wind projects under one or more 20-year renewable energy power purchase agreements. Qualified projects must be located within Virginia, West Virginia, eastern Indiana, Kentucky, Maryland, North Carolina, Ohio or Pennsylvania, be interconnected to the PJM Regional Transmission Operator, and have a minimum nameplate rating of 40 MW.²⁰ (Closed April 1, 2016)

¹⁴ https://goo.gl/uv2Mj8; https://goo.gl/K5U7TY.

¹⁵ https://goo.gl/b4dpPR.

¹⁶ https://goo.gl/toZd3Q.

¹⁷ https://goo.gl/l2hDuK.

¹⁸ https://goo.gl/iu1fM6.

¹⁹ https://goo.gl/fLSBAe.

²⁰ https://goo.gl/8S6l5C.

EXHIBIT B

Exhibit B: Florida RFPs for solar

The following is an illustrative list of recent RFPs in Florida.

- JEA issued an RFP for solar PV Power Purchase Agreements (PPA) in April of 2015, and entered into seven PPAs.¹ In 2015, JEA awarded a total of 31.5 MW of solar PPAs. Agreements have been finalized for five projects for a total of 25.5 MW.² Additionally, in December of 2014, JEA issued a solar photovoltaic RFP. Earlier, in May of 2009, JEA entered into a PPA with Jacksonville Solar, LLC to receive up to 15 MW from the solar plant located in western Duval County. The facility consists of approximately 200,000 photovoltaic panels, and generated 20,132 MWh in 2015.³
- 2. <u>Seminole</u> issued a solar RFP in March 2015 for a minimum of 2 MW and maximum of 20 MW to be in operation before November 2, 2016. Seminole received seventeen different offers with photovoltaic technology to be in service by the end of 2016. Seminole also incorporated a 2 MW solar photovoltaic facility into Seminole's ten-year plan. Finally, on March 21, 2016, Seminole finalized agreements for a 2.2 MW solar facility to be constructed in Hardee County.⁴
- 3. The <u>City of Tallahassee</u> issued a RFP for a PPA for a 10 MW utility scale solar photovoltaic project.⁵ During negotiations, the project developer offered double the capacity of the project, and the City Commission voted to authorize the PPA for 20 MW.⁶
- 4. <u>Lakeland Electric</u> issued an RFP in November of 2007, seeking an investor to purchase and install investor-owned photovoltaic systems totaling 24 megawatts. In October of 2008, the project was approved, and installed two years later. The projected reduction in annual fossilfuel generation is expected to be 31,800 megawatt-hours. In addition, Lakeland Electric issued another RFP in November 2007 for the expansion of its Residential Solar Water Heating Program. Lakeland's proposal was for the installation and operation of 3,000 10,000 solar residential water heaters, and annual projected energy savings ranged between 7,500 and 25,000 megawatt-hours.⁷

¹ Solar Photovoltaic Power Purchase Agreements, Dec. 22, 2014, available at https://goo.gl/X4C2hu.

² See JEA 2016 Ten-Year Site Plan, at 12.

³ See id. at 3.

⁴ Seminole response to Staff data request no. 36; *See also* Seminole 2016 Ten-year site plan, at 25; *See also* Seminole Electric Cooperative Issues Request for Proposals for Solar Energy, Mar. 31, 2015, https://goo.gl/fkRXXg.

⁵ 2015 Solar Procurement in the South, Oct. 6, 2015, https://goo.gl/jFaYnj.

⁶ See City of Tallahassee 2016 Ten-year site plan, at 41-42; *see also* Tallahassee prepares to add solar power to portfolio, Mar. 24, 2015, https://goo.gl/47IWrv.

⁷ See also Lakeland Electric's 2016 Ten-Year Site Plan.

EXHIBIT C

Exhibit C: Mergers between pipeline companies and IOUs/their affiliates.

The following is an illustrative list of mergers between pipeline companies and the IOUs/their affiliates.

- 1. AGL the largest natural gas distributor in the Southeast merged with Southern Company, which is the parent company of <u>Gulf Power</u>. The merger creates operations of more than 80,000 miles of pipelines.¹
- 2. There is a pending merger between <u>Duke</u> Energy and Piedmont. Both are partners on a \$5 billion Atlantic Coast Pipeline.²
- 3. NextEra Energy Partners, LP, parent company of <u>Florida Power & Light</u>, acquired NET Midstream, owner of seven long-term contracted natural gas pipeline assets.³

Mergers aside, <u>Tampa Electric Company</u> also has substantial stakes in gas infrastructure. TECO's subsidiary, SeaCoast Gas Transmission, L.L.C, operates a 25-mile pipeline system, which can deliver 100,000 MMBtus per day of natural gas to northeast Florida.⁴ Another affiliate, New Mexico Gas Company, also owns and operates pipelines.⁵

¹ Southern Company and AGL Resources complete merger, create a leading U.S. energy company, Southern Company, July 1, 2016, https://goo.gl/lHeHHU.

² North Carolina environmental groups oppose Duke-Piedmont merger, Crain's Raleigh-Durham, July 22, 2016, goo.gl/GSoCQ0

³ NextEra Energy Partners, LP completes the acquisition of natural gas pipelines in Texas, PR Newswire, Oct. 5, 2015, goo.gl/WlaS4X.

⁴ TECO Energy announces the formation of a new subsidiary, SeaCoast Gas Transmission, LLC, TECO Energy, Aug. 4, 2008, https://goo.gl/0ebj7J.

⁵ Overview — New Mexico Gas Company, https://goo.gl/jQtnwL.

EXHIBIT D

STATE OF GEORGIA

BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

IN RE:	
Georgia Power Company's) 2016 Integrated Resource Plan and) Application for Decertification of Plant) Mitchell Units 3, 4A and 4B, Plant Kraft) Unit 1 CT, and Intercession City CT)	Docket No. 40161
) Georgia Power Company's Application for) the Certification, Decertification, and) Amended Demand Side Management Plan)	Docket No. 40162

Stipulation

The Georgia Public Service Commission (the "Commission") Public Interest Advocacy Staff ("PIA Staff"), Georgia Power Company ("Georgia Power" or the "Company") and the undersigned intervenors (collectively the "Stipulating Parties") agree to the following stipulation as a resolution of the above-styled proceedings to consider the Company's 2016 Integrated Resource Plan (the "2016 IRP") and the Application for the Certification, Decertification, and Amended Demand Side Management Plan (the "2016 DSM Plan"). The Stipulation is intended to resolve all of the issues in these Dockets. The Stipulating Parties agree as follows:

Supply Side Plan

- 1. The 2016 IRP is approved as amended by this Stipulation.
- 2. Plant Mitchell Units 3, 4A and 4B, Plant Kraft Unit 1CT and Intercession City CT shall be decertified and retired as provided for in the 2016 IRP.
- 3. The Renewable Energy Development Initiative ("REDI") is approved and shall be increased such that it will procure 1,200 MW (150 MW of Distributed Generation ("DG") and 1,050 MW of utility scale resources). Utility scale procurement shall take place through two separate Requests For Proposals ("RFP"). The first RFP will be issued to the marketplace in 2017 and will seek 525 MW of renewables with in service dates of 2018 and 2019. The second RFP will be issued to the marketplace in 2019 and will seek 525 MW of renewables with in service dates of 2018 and 2019. The second RFP will be issued to the marketplace in 2019 and will seek 525 MW of renewables with in service dates of 2000 and 2021. No more than a total of 300 MW of wind resources shall be procured through REDI. Bid fees for the utility scale solicitation shall be set at five thousand dollars (\$5,000) or three hundred dollars per MW

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(\$300/MW), whichever is greater. The cost to implement and administer the REDI program shall be recovered through the fuel clause. Provided, however, that any costs recovery related to the ASI Prime Program in excess of ongoing ASI Prime costs shall be allocated to REDI and shall not be recovered through the fuel clause. All bid fees collected will be credited to the fuel clause.

- 4. In 2017, the Company shall issue an RFP for 100 MW of DG greater than 1kW but not more than 3 MW with a commercial operation date of 2018 or 2019. Contract terms will be up to 35 years and solar DG projects must interconnect at Georgia Power's owned distribution system. Bid fees for the DG solicitations shall be set at \$4/kW.
- 5. By the end of 2018, the Company shall procure an additional 50 MWs of customer sited DG projects. Such projects shall be greater than 1kW but not more than 3 MW and must have an installed DC capacity that is less than or equal to 125% of the actual annual peak demand of the customer's Premises in 2015 and be a current GPC customer at the time of award. Procurement shall be done through an application process and if oversubscribed, a lottery will be conducted. Participant fees for the DG solicitations shall be set at \$3/kW. Any MWs that are unsubscribed from the customer sited program shall be allocated to the DG RFP reserve list. Customer sited projects will be paid avoided costs using the process as described below in item 8(a).
- 6. The specific process that will be utilized for the evaluation (such as whether to use a project and/or portfolio analysis) for projects submitted into REDI will be finalized during the review and approval of the REDI RFP documents.
- 7. The Renewable Cost Benefit framework ("RCB") as provided in paragraph 8(a) shall be utilized in the evaluation of bids received through the REDI RFPs for utility scale and DG projects. The Company and Staff will work collaboratively to develop a process and recommendations for the continued implementation of RCB. Within (4) months from the issuance of the Final Order in this case, the Company and Staff will file their proposal with the Commission for implementation of RCB. If an agreement is reached between the Company and Staff on implementation of RCB, the Company and Staff can recommend to the Commission utilization of the full RCB in REDI.
- 8. The RCB shall be modified for use in the REDI program as follows:

(a) The Company shall evaluate the bids received in response to REDI RFPs using the RCB. The evaluation of REDI proposals will be limited to the consideration of Avoided Energy and Deferred Generation Capacity cost components consistent with the Framework methodology. Further, the Company will evaluate the appropriate transmission and distribution costs and benefits on a case by case basis as proposed in the Framework document.

(b) Once the evaluation in 8(a) is concluded the Company will conduct, for information purposes only, an evaluation using the entire RCB as filed by the Company to allow Staff

and the Independent Evaluator ("IE") to gain familiarity with the RCB. The evaluation will include all aspects of the Framework including specifically, Generation Remix, Support Capacity, and Bottom Out Adjustments. The Company will file its results with the Commission.

- The Additional Sum for utility scale resources procured through REDI shall be set at 8.5% of shared savings. This amount shall be levelized and recovered annually for the term of the PPA.
- 10. The Company's closed ash pond solar demonstration project is approved as filed by the Company. The Company will be required to file quarterly construction monitoring reports and will be required to demonstrate the reasonableness and prudency of any recovery in excess of the budget for this project filed in the 2016 IRP. The Simple Solar program is approved with the modifications to the sourcing of the program as recommended by Staff.

In addition, the Company's High Wind Study is approved as filed. The Company agrees to file quarterly reports providing the status of the High Wind Study. The Staff and Company will collaborate on what, if any, information from the wind study will be made available to interested parties.

- 11. The Commission approves an additional 200 MW of self-build capacity for use by the Company to develop additional renewable projects in collaboration with customers, including potential projects at Robins Air Force Base and Fort Benning. The projects must be at or below the Company's avoided costs. No more than 75 MW of the 200 MWs provided for in this provision may be used for non-military customer projects. For the non-military customer projects, the Company must demonstrate that the project meets a special public interest need and could not reasonably be achieved using the competitive bid process. The RECs for the non-military customer projects shall accrue to the benefit of all customers.
- 12. The Company shall consider the development of a renewable Commercial and Industrial Program. No more than 200 MW shall be allocated for such a program and such program must be approved by the Commission before implementation. The Company shall only consider program options that will result in delivering value to all of its customers and will benchmark such programs to the last accepted proposal from the Company's utility scale REDI program.
- 13. Staff and the Company shall work together to address retirement study and other modeling issues. This process should begin within six months of the final order being issued in this proceeding and must conclude at least 12 months prior to the Company's filing of the 2019 IRP.
- 14. For purposes of the Company's IRP evaluations the long term Southern System planning reserve margin shall be raised to 16.25%. The Company shall meet with Commission Staff within 6 months of a final order in this case to discuss the timing of future Expected

Unserved Energy studies. The Company will report to Staff once all operating companies have approved for utilization the long term planning reserve margin adopted by this provision.

- 15. The Company agrees to minimize all capital expenditures on Plant McIntosh Unit 1 and Plant Hammond Units 1-4 through July 31, 2019. The Company agrees to annual limits on all capital expenditures of \$1 million for McIntosh 1 and \$5 million for Hammond 1-4¹. The Company agrees to make a filing with the Commission prior to incurring expenditures that exceed the annual limit.
- 16. The measures taken to comply with the existing government imposed environmental mandates necessary for the Company to implement its environmental and compliance plan as presented in Technical Appendix Volume 2, Summary of Capital Expenditures, Closures, and O&M Expenses filed as part of the 2016 IRP are approved subject to the limits outlined in No. 15 above regarding Plant McIntosh Unit 1 and Hammond Units 1-4. This approval does not preclude the Commission from reviewing prudence of the actual expenditures made to effectuate the compliance plan.
- 17. The remaining net book values of Plant Mitchell Unit 3 shall be reclassified as a regulatory asset and the Company shall continue to provide for amortization expense at the same rate as determined in the Company's 2013 base rate case. Recovery of the remaining balance as of December 31, 2019 will be deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

Any unusable M&S inventory balance remaining at the date of the unit retirement shall be reclassified as a regulatory asset and deferred for consideration in the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the recovery mechanism and appropriate period in which the costs should be recovered if applicable. Parties may argue their respective positions on that issue in the 2019 base rate case.

18. Any over or under recovered cost of removal balances for each Retirement Unit shall be deferred for consideration until the Company's 2019 base rate case. The Stipulating Parties reserve the right to make any arguments, including policy and legal arguments, on the appropriate period in which the costs should be recovered. Parties may argue their respective positions on that issue in the 2019 base rate case.

¹ The Hammond Units 1-4 \$5 million value represents the cumulative annual amount for all four units. This provision does not apply to expenditures required for retirement obligations.

- 19. The Company shall report to the Commission concerning progress on the dismantlement and remediation of the Plant Kraft generating plant site and the Company shall provide the Commission with appraised values of any land at that site that the Company would propose to donate to the Georgia Ports Authority, including information regarding whether the appraised value exceeds the Company's net book value of such land.
- 20. The decision whether to accept, modify or defer consideration of the Company's request for authority to capitalize additional costs to preserve new nuclear shall be a policy decision for the Commission. Adoption of this provision within this stipulation does not preclude any Party from making any argument for or against the Company's request in this regard, nor does this agreement or this provision within this agreement suggest that the Commission must or should (or should not) consider this question as part of this IRP.
- 21. When filing the 2019 IRP or when filing any updates to the IRP prior to the 2019 IRP filing, the Company agrees to provide the Commission Staff working copies of all models used in the development of that IRP, with each configured to replicate inputs used to derive results incorporated in its base case scenario within 10 days after the IRP or update to the IRP is filed.
- 22. In conjunction with the ongoing level of review and analysis required by this agreement, Georgia Power will agree to pay for any reasonably necessary specialized assistance to the Staff in an amount not to exceed \$300,000 annually. This amount paid by Georgia Power under this paragraph shall be deemed as necessary cost of providing service and the Company shall be entitled to recover the full amount of any costs charged to the utility.
- 23. The Electric Transportation Initiatives and associated costs identified in the 2016 IRP are not, and have not been converted into, jurisdictional expenses that become the responsibility of ratepayers. Each party reserves the right to address these costs and the merits of the program through the Annual Surveillance Report process and future rate cases.

Demand Side Plan

- The Company's 2016 Demand Side Management ("DSM") Plan and Application for Certification, Decertification and Amended DSM Plan is approved as amended by this Stipulation.
- 2. Georgia Power will continue to treat DSM as a priority resource in accordance with prior Commission precedent. For the calculation of long term percentage rate impacts, the Company will work with Commission Staff to come up with a methodology within 12 months of the issuance of the final order.

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- Georgia Power will enter discussions over the next three years with Staff and DSMWG members on the value of a Residential Mid-Stream Retail Products Program.
- 4. Georgia Power will develop a Technical Reference Manual prior to the Company's next IRP filing and will update it every three years thereafter. The Company will work closely with Staff and members of the DSMWG and DSMWG members may also propose new measures to be added at any point in the measure evaluation process. The DSM Program Planning Approach filed as Staff Exhibit BSK8 will otherwise remain unchanged other than "Technology Catalog" will be replaced with "Technical Reference Manual" and the dates will be updated to reflect 2017 through 2019.
- 5. Georgia Power will agree to the budget adjustments as provided in exhibit 8 attached to this Stipulation as amended.
- 6. Georgia Power will receive an Additional Sum equal to 8.5% of actual net benefits based on net energy savings from the Program Administrators Cost Test ("PACT"). Once the Additional Sum amount as calculated exceeds the annual program costs, the portion of the Additional Sum that exceeds the program cost shall be calculated based on 4% of the actual net benefits based on net energy savings from the PACT.
- Georgia Power will work with Staff and the Company's implementation contractor for the Residential Behavioral Program to find ways to include more customers in the program.
- The Company will make a concerted effort to obtain at least 25% of portfolio savings each year from the Residential sector.
- 9. Once a program implementer is selected and plans for all proposed programs are drafted and completed, the plans will be provided to Staff for review prior to implementation of the programs. The current review and approval process reached in an agreement between Staff and the Company in 2014 will continue, and the Company agrees to discuss further refinements and revisions to the process. In order to change the process both Staff and the Company must agree to the recommended changes.
- 10. The Company will provide detailed evaluation plans for each of the approved DSM programs within 120 days of the selection of Program Implementers for each of the certified programs. If necessary, the Company may request, and Staff may unilaterally grant, additional time to complete the detailed evaluation plans for each of the approved DSM proposals.
- 11. The Company will agree to a Commercial and Residential Building Usage Data awareness option at the cost of \$300,000 for 2017 and \$100,000 annually for 2018 and 2019, and such costs will be added to the DSM Consumer Awareness budget. This option will be available to customers within one year from the date of the final order in

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this docket. There will be no assumed energy savings or goals attributed to this customer awareness option.

- The Company and Staff agree to a \$2.5 million annual pilot budget for DSM and energy 12. efficiency pilot programs. Staff will be notified before the start of such pilots.
- The Company agrees to the Staff recommendation for the Learning Power program 13. annual budget to be \$3 million.
- The Company agrees to the Staff recommendation against shifting residential and 14. commercial customer awareness to cross-cutting costs.
- The current DSM true-up process filed in Docket No. 36499 on October 18, 2013, will 15. continue through 2020. Although the DSM tariffs will remain at current levels until rates are adjusted in 2020, the true-up review process will continue on an annual basis.

Agreed to this 23rd day of June, 2016.

On behalf of the Georgia Public Service Commission Public Interest Advocacy Staff

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On behalf of Georgia Power Company

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On behalf of Clean Line Energy Partners LLC David Beny authorized person

On behalf of

On behalf of Georgie Association

Of Manufacturers

On behalf of Georgia Industrial Group

On behalf of

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- The Company and Staff agree to a \$2.5 million annual pilot budget for DSM and energy 12. efficiency pilot programs. Staff will be notified before the start of such pilots.
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- The current DSM true-up process filed in Docket No. 36499 on October 18, 2013, will 15. continue through 2020. Although the DSM tariffs will remain at current levels until rates are adjusted in 2020, the true-up review process will continue on an annual basis.

Agreed to this 23rd day of June, 2016.

On behalf of the Georgia Public Service Commission Public Interest Advocacy Staff

andon F. Marzo

On behalf of Georgia Power Company Georgia Industrial on behalf of

On behalf of The Georgia Large Scale Solar Association

On behalf of

On behalf of Georgia State Building and Construction Trades Council

On behalf of

Bruce W. Buckt On behalf of Southern Wind Energy

Association

EXHIBIT E

February 29, 2016

Via Electronic Mail

Supervisor Marc Harris Power Plant NPDES Permitting, Industrial Wastewater Section Florida Department of Environmental Protection

Re: Bringing Florida Coal Plants Into Compliance With The New Effluent Limitations Guidelines

Dear Supervisor Harris:

As you know, the U.S. Environmental Protection Agency ("EPA") updated the Effluent Limitations Guidelines ("ELGs") for steam electric power plants to protect our waters from the toxic pollutants in these generators' discharges.¹ Reflecting decades of advances in water quality science and control technology,² the ELGs became effective on January 4, 2016. Now coalburning³ power plants across the country must come into compliance with the ELGs "as soon as possible;" for many plants the deadline is November 1, 2018.⁴ The undersigned groups and our tens of thousands of Florida members therefore urge you, as the supervisor of power plant NPDES permitting, to:

- 1. Promptly issue draft revised NPDES permits and fact sheets for Florida coal plants to require these plants to comply with the ELGs by November 1, 2018, unless you conclude that a later date is appropriate based on a well-documented justification that is consistent with EPA's guidelines in the final rule and the public interest in securing vital water protections as soon as possible.
- 2. Take public comment for no less than 60 days on draft NPDES permits and fact sheets for Florida coal plants that include your ELGs compliance determinations.
- 3. Work with the operators of the three Florida coal plants without NPDES permits or announced plans for retirement, and other stakeholders, to ensure that these plants achieve timely compliance with the applicable requirements in the ELGs.

¹ U.S. EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category*, 80 Fed. Reg. 67,837 (Nov. 3, 2015), codified at 40 C.F.R. part 423.

² See 80 Fed. Reg. at 67,840.

³ See 80 Fed. Reg. at 67,839, n. 1 ("power plants covered by the ELGs use nuclear or fossil fuels, such as <u>coal</u>, oil, or natural gas, to heat water in boilers, which generate steam." [emphasis added]). ⁴ See, e.g., 40 C.F.R. § 423.13(g)(1)(i) (establishing deadline for compliance with FGD wastewater

standards; identical language appears in the provisions for other regulated waste streams).

4. Work with all Florida coal plant operators, fellow regulators, and other stakeholders to determine compliance obligations and timelines for all other applicable water-side requirements.

As we discuss below, timing is critical. Through the permit renewal process, making prompt compliance determinations will help attain and maintain safe water quality in Florida. Prompt compliance determinations will also allow fellow regulators to assess whether it is more prudent to retire—rather than spend huge sums of public monies to retrofit—these aging coal plants in the rapidly evolving regulations and market conditions concerning coal and carbon.

In short, our overarching request is that you take swift action to determine what it will take to bring *all* Florida coal plants into timely compliance with *all* applicable water-side requirements, set deadlines for the same, and meet with us to discuss the way forward.

I. DEP Should Promptly Issue Draft Permits And Fact Sheets For Florida Coal Plants Incorporating The ELGs And Specifying The "As Soon As Possible" Compliance Deadline.

The ELGs impose stringent, technology-based effluent limitations on the discharges of several common types of effluent (i.e., waste streams) from coal plants, including fly ash and bottom ash transport waters, and wastewater from flue gas desulphurization ("FGD") systems.⁵ Under the Clean Water Act, it is the responsibility of state permitting authorities to incorporate the ELGs into the NPDES permits for coal plants "as a floor or a minimum level of control."⁶ Just as it is the responsibility of the coal plant operators to "immediately begin"—"even prior to the permit renewal process"—their ELGs compliance analyses, and convey to state authorities the information they need to complete independent evaluations.⁷

In particular, when revising permits for direct dischargers—facilities that discharge to surface waters—state permitting authorities must determine the compliance deadline for the ELGs, which is to be "as soon as possible beginning November 1, 2018, but no later than December 31, 2023." To be clear, the phrase "as soon as possible" means November 1, 2018, unless the permitting authority establishes a later date based on a well-documented justification and the

⁵ See 40 C.F.R. § 423.13.

⁶ 80 Fed. Reg. at 67,882.

⁷ *Id.* at 67,882-83 ("Regardless of when a plant's NPDES permit is ready for renewal, the plant should <u>immediately begin</u> evaluating how it intends to comply with the requirements of the final ELGs. In cases where significant changes in operation are appropriate, the plant should discuss such changes with the permitting authority and evaluate appropriate steps and a timeline for the changes, <u>even prior to the permit renewal process</u>." [emphasis added]).

authority's case-by-case consideration of certain enumerated factors in the final rule, discussed further below.

The November 1, 2018, compliance deadline is achievable. EPA's rulemaking record shows that, depending on the scope of required retrofit at a particular coal plant, industry itself projects that the total time needed for fly ash and bottom ash system retrofits ranges from 27 to 36 months, from the start of conceptual engineering to final commissioning.⁸ With appropriate planning and direction from state permitting authorities, many plants thus can and should be required to bring their operations into compliance by November 1, 2018, especially given that the updates to the ELGs were developed and thus anticipated by industry over several decades.

EPA rightly urges permitting authorities to "provide a well-documented justification for how [they] determined the 'as soon as possible' date in the fact sheet or administrative record for the permit," and to "explain why allowing additional time to meet the limitations is appropriate," if that is the authority's conclusion.⁹ EPA specifies that any determination that a later date is appropriate should be substantiated by the public record and reflect consideration of the following factors:

- * "Time to expeditiously plan (including time to raise capital), design, procure, and install equipment to comply with the requirements [in the ELGs]."¹⁰ EPA explains that "the permitting authority should evaluate what operational changes are expected at the plant to meet the new BAT limitations for each waste stream, including the types of new treatment technologies that the plant plans to install, process changes anticipated, and the timeframe estimated to plan, design, procure, and install any relevant technologies."¹¹
- Changes being made or planned to bring the coal plant into compliance with Clean Air Act requirements, as well as the requirements for the disposal of coal combustion residuals under Subtitle D of the Resource Conservation and Recovery Act.¹²
- For FGD wastewater requirements only, an initial commissioning period to optimize the installed equipment.¹³ EPA explains that the "record demonstrates that plants installing

⁸ Utility Water Act Group, Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Sept. 30, 2013), Attach. 11: Retrofitting Dry Bottom Ash Handling, Attach 13: Retrofitting Dry Fly Ash Handling.

⁹ See U.S. EPA, Technical Development Document for the Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Sept. 2015), at p. 14-11, *available at* http://goo.gl/PpzQ4F [hereinafter "TDD"].

 $^{^{10}}$ *Id*.

¹¹ Id.

¹² 40 C.F.R. § 423.11(t)(2).

the FGD technology basis spent several months optimizing its operation (initial commissioning period). Without allowing additional time for optimization, the plant would likely not be able to meet the limitations because they are based on the operation of optimized systems."¹⁴

• Other factors as appropriate.¹⁵

Consistent with these EPA guidelines and the public interest in securing vital water protections as soon as possible, you should incorporate the ELGs into the NPDES permits for eight Florida coal plants—Big Bend, Crist, Crystal River, Northside/St. Johns, Seminole, Stanton, Indiantown and Polk.

As you are aware, NPDES permits for the first six of these plants (Big Bend through Stanton) expire this year or next year. Therefore, you should be working with their operators to ensure that they do, in fact, "immediately begin" their ELGs compliance analyses, and are prepared to provide you and the public the information needed to evaluate and set the "as soon as possible" ELGs compliance deadline in their NPDES renewal permits.

Moreover, even if Indiantown and Polk's NPDES permits do not expire until 2019, their operators have the same responsibility to "immediately begin"—"even prior to the permit renewal process"—their ELGs compliance analyses, and, similarly, you should be working with these plant's operators to expeditiously set and achieve the "as soon as possible" ELGs compliance deadline.

Therefore, we urge you to make prompt compliance determinations for all eight coal plants, <u>first</u>, by collecting and making publicly available the information from their operators regarding their potential to comply with the ELGs by November 1, 2018, and, <u>second</u>, by closely scrutinizing and verifying this information as you revise NPDES permits and adjudicate any requests to extend the ELGs compliance deadline beyond November 1, 2018.

With respect to extension requests, we recognize that for other regulations, for instance, the Mercury and Air Toxics Standards, it has been the Department of Environmental Protection's ("DEP") practice to carefully review and grant such requests only in exceptional cases. Similarly, DEP should continue this practice here and use its broad information collection powers and stakeholder engagement process to help adjudicate the merits of any extension requests for ELGs compliance.

¹³ 40 C.F.R. § 423.11(t)(3).

¹⁴ TDD at 14-11.

¹⁵ 40 C.F.R. §423.11(t)(4).

II. DEP Should Take Public Comment For No Less Than 60 Days On Draft NPDES Permits And ELGs Compliance Determinations For Coal Plants.

Because of the significance of the water protections in the ELGs and the findings you must make regarding the compliance date, as discussed above, we urge you to take public comment for no less than 60 days on these draft NPDES renewal permits and compliance determinations for the ELGs. Doing so is entirely consistent with DEP's mission to serve the public interest and to conduct its environmental oversight responsibilities with transparency.¹⁶

III. DEP Should Work With Florida Coal Plant Operators That Do Not Have NPDES Permits, And Other Stakeholders, To Ensure That Their Plants Achieve Timely Compliance With The Applicable Requirements In The ELGs.

Three coal plants in Florida—C.D. McIntosh, Jr., Cedar Bay, and Deerhaven—are not covered by NPDES permits but nonetheless must assure that the toxic pollutants in their effluent are properly treated to meet the requirements in the ELGs. For example, the McIntosh plant in Lakeland discharges effluent containing toxic pollutants such as mercury to publicly owned treatment works. These discharges are subject to revised Pretreatment Standards for Existing Sources (PSES) in the ELGs.¹⁷ The PSES are self-implementing, meaning these requirements apply directly, without the need for any permit revision, and must be met by the November 1, 2018, compliance deadline in the final rule.¹⁸ Sierra Club provided McIntosh's operator, Lakeland Electric, with a compliance analysis specifying the implications of the PSES for this plant.¹⁹ We urge you to work with the DEP PSES coordinator, the operators of all three plants, as well as other stakeholders, to ensure that they achieve timely compliance with the applicable requirements in the ELGs.

IV. Timing Is Critical.

As we noted above, timing is critical. Through the water permit renewal process, you should make prompt ELGs compliance determinations for three key reasons:

First, prompt ELGs compliance determinations, including setting the "as soon as possible" deadline, are needed to secure safe water for Floridians. EPA updated the ELGs to address the "outstanding public health and environmental problem" related to the discharge of effluent containing toxic and other pollutants from power plants, including Florida's aging coal plants.²⁰

¹⁶ See, e.g., FDEP Mission Statement & Objectives, *available at* http://goo.gl/tTk3mp.

¹⁷ See 40 C.F.R. § 423.16.

¹⁸ Id.

¹⁹ See Sierra Club letter to General Manager Ivy of January 26, 2016 and exhibits, on file with DEP.

²⁰ 80 Fed. Reg. at 67,840-41.

Indeed, the "ELGs that EPA promulgated and revised in 1974, 1977, and 1982 are out of date" and, as a result, permits issued to coal plants under those previous, outdated ELGs "do not adequately control the pollutants (toxic metals and other) discharged by this industry, nor do they reflect relevant process and technology advances that have occurred in the last 30-plus years."²¹

Furthermore, as you know, NPDES permits have a maximum term of five years.²² The limited permit duration and the anti-backsliding requirement in the Clean Water Act aim to achieve gradual, iterative, but continual progress towards restoring the nation's waters. As the D.C. Circuit has explained, "[t]he essential purpose of this series of progressively more demanding technology-based standards was not only to stimulate but to press development of new, more efficient and effective technologies."²³ As pollution control technologies improve, higher standards are incorporated into the NPDES permits of existing facilities upon renewal. <u>This makes timely renewal of NPDES permits a linchpin of the Clean Water Act, and an essential part of your office's responsibilities</u>.

Second, prompt ELGs compliance determinations will help assure that coal plant operators do, in fact, reduce as soon as possible the toxic discharges into our waters, thus avoiding regulatory uncertainty and any avoidable delay in achieving these vital water protections.

Third, prompt ELGs compliance determinations will help <u>level the playing field</u> between coal plants with NPDES permits and those without them, so that all Florida coal plants achieve compliance with the ELGs as soon as possible.

For all these reasons, we urge you to make prompt determinations of what it will take to bring Florida coal plants into compliance with the ELGs, and promptly adjudicate any requests to extend the compliance deadline beyond November 1, 2018.

V. DEP Should Do Its Part To Protect Consumers From Piecemeal Regulatory Compliance Decisions That Fail To Identify And Pursue Cost-Effective Alternatives To Spending Billions Of Dollars To Retrofit Florida's Aging Coal Plants.

As we noted above, fellow regulators are deciding whether to spend huge sums of public monies on retrofitting aging coal plants to meet several environmental regulations with fast-approaching compliance deadlines. Indeed, because burning coal is one of the most polluting and

²¹ 80 Fed. Reg. at 67,840 [emphasis added].

²² See 33 U.S.C. § 1342(b)(1)(B).

²³ Natural Res. Def. Council v. U.S. Envtl. Prot. Agency, 822 F.2d 104, 124 (D.C. Cir. 1987).

increasingly costly ways to generate electricity, regulators—and coal plant operators—will soon decide whether to take as much as <u>4 billion dollars</u> from Floridian families and businesses for retrofits, alone, to these plants.²⁴ Yet there has not been any comprehensive accounting of just how much more Floridians may have to pay to rely on these plants to keep the lights on, much less a fair comparison to available alternatives such as retiring these plants and investing instead in modern clean energy resources such as solar, wind, energy efficiency, and storage that are at <u>record low prices</u>.²⁵ Indeed, while operators project coal plant retrofits may cost 4 billion dollars or more, they admit this huge sum does not account for all the costs and risks associated with relying on coal plants in the rapidly evolving regulations and market conditions concerning coal and carbon.²⁶

We urge you to do your part to fill this acute information gap, <u>first</u>, by providing much needed clarity regarding ELGs compliance obligations and timelines for coal plants and, <u>second</u>, by providing the same for other applicable water-side requirements. For example, four Florida coal plants—Big Bend, Crist, Crystal River, Northside—use antiquated once-through cooling systems that needlessly harm millions of aquatic organisms, potentially including federally listed species. In fact, it has been unlawful to use such rudimentary cooling systems when building new power plants since 2001,²⁷ and generally none have been built since the 1980's precisely because of their adverse biological impacts.²⁸ To be sure, aging coal plants such as Big Bend, Crist, Crystal River, and Northside also must come into compliance with modern, species-protecting cooling standards under the Endangered Species Act and the Cooling Water Intake Structure Rule. Therefore, we urge you to work closely with the operators, fellow regulators, and other stakeholders to comprehensively identify Florida coal plants' water-side compliance obligations and timelines. The sooner, the better. As we discussed above, huge sums of public monies and vitally important water resources are at stake.

Thank you for your consideration, and we look forward to the opportunity to meet with you to discuss the way forward.

²⁴ See, e.g., Sierra Club letter of December 12, 2015, Table 1 (showing electric utilities' incomplete regulatory compliance costs estimates totaling 3-4 billion dollars through 2024), *available at* http://goo.gl/CT8l1j [hereinafter "2015 Letter"].

²⁵ See generally id.

²⁶ See 2015 TYSP First Supplemental Staff Data Request No. 38, *available at* http://goo.gl/nhBGEi; *see also* 2015 Letter, 7-8 (discussing incomplete nature of utility retrofit cost estimates).

²⁷ See 66 Fed. Reg. 65256 (2001) ("Phase I Rules"); see also 40 CFR §§125.80(a), 125.81(a) (2008).

²⁸ See, e.g., 65 Fed. Reg. 49060, 49087 and 49094 (Aug. 10, 2000) ("Draft Phase I Rules") (noting that since the 1970's there has been extensive and increasing recycling and reuse of cooling water and that by the year 2000 most new industrial facilities used closed-cycle cooling systems).

Sincerely,

Diana Csank Sierra Club

Kathleen E. Aterno Clean Water Action

Pete Harrison Waterkeeper Alliance

Justin Bloom Suncoast Waterkeeper

Harrison Langley Collier County Waterkeeper Alisa Coe EarthJustice

Jerry Phillips Florida PEER

Laurie Murphy Emerald Coastkeeper

Lisa Rinaman St. Johns Riverkeeper Susan Glickman Southern Alliance for Clean Energy

Dan Tonsmeire Apalachicola Riverkeeper

Neil A. Armingeon Matanzas Riverkeeper

Rachel Silverstein, Ph.D. Miami Waterkeeper

Cc: Paula Cobb, DEP Greg Brown, DEP Richard Tedder, DEP Julie Brown, PSC Mark Futrell, PSC Tom Ballinger, PSC J.R. Kelly, OPC

EXHIBIT F



September 26, 2016

Via email and postal mail

Supervisor Marc Harris Power Plant NPDES Permitting, Industrial Wastewater Section Florida Department of Environmental Protection marc.harris@dep.state.fl.us

Re: Bringing coal burning operations at the Crystal Energy Generating Complex Units 4 and 5 into compliance with ground and surface water protection standards in the current NPDES permit renewal process (Permit No. FL0036366)

Dear Supervisor Harris:

On behalf of our tens of thousands of Florida members and supporters and the undersigned groups, the Sierra Club respectfully submits these comments on the Draft Permit issued by the Florida Department of Environmental Protection ("DEP") for National Pollutant Discharge Elimination System Permit ("NPDES") Permit No. FL0036366. This permit governs discharges from Units 4 and 5 at Duke Energy Florida's ("DEF") Crystal River Energy Generating Complex ("CREC") into Crystal Bay, a Class II marine water and part of the Gulf of Mexico.

As stated in our prior letter of February 29, 2016,¹ we have a vital interest in bringing the toxic coal burning operations in Florida into compliance with the applicable public health and safety standards. Our comments here focus on the necessary changes to Permit No. FL0036366 to bring CREC into compliance with the revised effluent limitation guidelines for steam electric power plants ("ELGs")² and the new standards for coal combustion residuals ("CCR") ³ storage and disposal (the "CCR Rule").⁴

¹ Letter from Diana Csank, Sierra Club, to Marc Harris, Florida Department of Environmental Protection (February 29, 2016).

² U.S. EPA, *Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; Final Rule,* 80 Fed. Reg. 67,838 (Nov. 3, 2015) (revising 40 C.F.R. Part 423) [hereinafter "ELGs"].

³ Coal combustion residuals include "fly ash, bottom ash, boiler slag, and flue gas desulfurization materials generated from burning coal for the purpose of generating electricity by electric utilities and independent power producers." 40 C.F.R. § 257.53.

⁴ U.S. EPA, *Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities; Final Rule,* 80 Fed. Reg. 21,302 (Apr. 17, 2015), as amended by Technical Amendments to the Hazardous and Solid Waste

To support our comments, we enclose two exhibits: Exhibit 1, by one of the state's preeminent hydrogeologists, Dr. Mark Stewart, assesses the coal disposal at CREC including the pathways for toxic contaminants in the Ash Landfill and Percolation Pond to leach into the Floridan aquifer and Crystal Bay. Exhibit 2, by Dr. Ranajit Sahu— an expert with over twenty-five years of experience in environmental, mechanical, and chemical engineering, including coal-fired power plants— examines the timeline for CREC Units 4 and 5 to achieve compliance with a zero discharge standard for bottom ash.

As detailed below and in the enclosed exhibits, per the ELGs, by November 1, 2018, the final permit should require DEF to eliminate all discharges of bottom ash and flue gas mercury control ("FGMC") wastewaters, and meet new limitations for pollutants in flue gas desulfurization ("FGD") wastewater and combustion residual leachate for the following reasons, again, detailed further below:

- The final permit should set November 1, 2018, as the "as soon as possible" deadline for DEF to eliminate bottom ash wastewater discharges from Units 4 and 5.⁵ It is well documented that a zero discharge best available technology economically achievable ("BAT") standard for bottom ash wastewater can be readily achieved in 27 to 30 months, rather than the 44 months that DEF proposed and DEP has endorsed in the Draft Permit.⁶ In fact, the permitting record here indicates that DEF is well-positioned to meet the standard in even less time, such that the default, November 1, 2018, deadline should apply.
- The final permit should include the applicable ELG provisions for CREC's FGMC and FGD wastewaters as they are discharged to groundwater in Percolation Ponds and directly hydrologically connected to Crystal Bay and the Gulf of Mexico, "waters of the United States."⁷
- The final permit should set November 1, 2018, as the deadline for DEF to meet the zero discharge standard for CREC's discharges of FGMC wastewater.⁸ Additionally, before that deadline, the permit should require DEF to meet the best practicable control technology available ("BPT") limitations for total suspended solids ("TSS") and oil and grease effluent limits and begin monitoring flows daily.⁹
- The final permit should require the FGD wastewater to meet strict BAT effluent limits

⁹ 40 C.F.R. § 423.12(b)(11).

Management System; Disposal of Coal Combustion Residuals from Electric Utilities—Correction of the Effective Date, 80 Fed. Reg. 37,988 (Jul. 2, 2015) (revising 40 C.F.R. §§ 257 & 261) [hereinafter "CCR Rule"].

⁵ See 40 C.F.R. § 423.11(t) (defining the phrase "as soon as possible" to mean Nov. 1, 2018, unless a later date is specifically justified); § 423.13(k)(1) (requiring compliance with bottom ash wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

⁶ See Exhibit 2.

⁷ 33 U.S.C. §§ 1311(a), 1342(a), 1362(14); 40 C.F.R. § 423.13(g) and (i).

⁸ 40 C.F.R. § 423.13(i)(1) (requiring compliance with FGMC wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

for arsenic, mercury, selenium and nitrate/nitrite by December 2018, or even sooner if possible.¹⁰ Additionally, the permit should require, effective immediately, FGD wastewater to meet the BPT TSS and oil and grease effluent limits and daily monitoring of the same.¹¹

The final permit should require combustion residual leachate to meet all applicable technology and water quality based effluent limits, not only for discharges that drain to the runoff collection system, but also for discharges to the seawater discharge canal and Crystal Bay.¹²

As detailed below and in the enclosed exhibits, per the CCR Rule, the final permit should require DEF to meet all of the applicable new safety standards for coal ash disposal. This includes the standards aimed at protecting groundwater and surface—here, most notably, the Floridan aquifer and Crystal Bay:

- Toxic coal ash contaminants associated with CCR—arsenic, boron, manganese, molybdenum, selenium, sulfate, and thallium—are exceeding state and federal safety limits at wells downgradient from the unlined Ash Landfill,¹³ as DEP is aware and even predicted.¹⁴ Because there is no protective barrier, CCR waste in the landfill is in direct contact with the Floridan aquifer and groundwater that is hydrologically connected to Crystal Bay.
- The CCR Rule requires cleanup of the CCR that has accumulated in the unlined Ash Landfill.¹⁵ To prevent unauthorized discharges and further contamination, and to comply with federal and state waste and water quality regulations, the final permit should require DEF to take corrective action as soon as possible by removing all CCR from the Ash Landfill and decontaminating the site.
- CREC is in one of the country's most unstable areas, in karst terrain, and under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles of CREC. Siting CCR waste facilities here puts ground and surface waters at risk of releases of toxic CCR waste into the underlying aquifer, due to limestone dissolution and collapse.¹⁶
- DEF must comply with prohibitions, designed to protect public waters, on siting coal ash

¹⁰ See 40 C.F.R. §423.13(g)(1)(i) (requiring compliance with FGD wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

¹¹ 40 C.F.R. § 423.12(b)(11).

 $^{^{12}}$ 40 C.F.R §§ 423.12(b)(11) and 423.13(l).

¹³ See Exhibit 1 and Section G below; see also 40 C.F.R. §§ 141.62,141.66, 257.95(h); Fla. Admin. Code. R. 62-520.420 (2016).

¹⁴ Memorandum from Don Kell to Hamilton Oven, Jr., July 15, 1981 at 3, 4, 7 (hereinafter "Ash Landfill Interoffice Memo").

¹⁵ 40 C.F.R. §§ 257.95(g)(5); 257.96; 257.101(a).

¹⁶ See Exhibit 1.

waste facilities in unstable areas (i.e., Florida's karst terrain).¹⁷ To do so, DEF must move CCR disposal offsite if DEF fails to prove that the status quo—storing CCR in CREC's facilities—is somehow safe.¹⁸ Because the Ash Landfill cannot meet the safety standards in the CCR Rule, and the facility cannot be effectively retrofitted, it cannot receive CCR after April 19, 2019. Instead, DEF will be required to close the landfill and move disposal offsite.

DEF applied to renew Permit No. FL0036366, governing surface water discharges from Units 4 and 5 in January 2016.¹⁹ Notice of the Draft Permit was received by Sierra Club via email on Friday, August 26, 2016. The applicant's name is DEF Florida, LLC, and its address is 15760 Power Line St., Crystal River, FL 34428. The discharge covered by the proposed Draft Permit, File No. FL00036366-013-IW1S, is located in Citrus County.

We respectfully submit this material to help inform DEP's renewal of Crystal River's NPDES permit, to raise our concerns that the Draft Permit does not assure compliance with state and federal law, and to urge DEP to revise the Draft Permit and include requirements for CREC to comply with all applicable ground and surface water protection standards.

BACKGROUND

The Crystal River Energy Generating Complex ("CREC") is located in Citrus County, Florida and is owned and operated by DEF. CREC Units 4 and 5 are pulverized coal-burning steam electric generating units that were placed into service in 1982 and 1984 respectively. The 4,729-acre coastal site in Florida's Big Bend is connected to Crystal Bay, a Class II²⁰ marine water and part of the Gulf of Mexico, via a seawater discharge canal that releases the plant's wastewater.

Crystal Bay is a shallow embayment of the Gulf of Mexico, midway between the Withlacoochee River to the north and the Crystal River to the south. Undeveloped portions of CREC include wetlands and salt marshes. Crystal Bay includes a variety of habitats that support vital aquatic resources, including the federally-listed species identified below. Open water habitats in Crystal Bay cover saltwater, tidally-influenced water, and tidal freshwater areas and include artificial structures, coastal tidal rivers and streams, oyster reefs, salt marshes, subtidal unconsolidated marine/estuary sediment habitats, and submerged aquatic vegetation habitats such as seagrasses and algae. The bottom of Crystal Bay provides benthic habitats, with characteristics dictated by salinity, tides, and substrate type.²¹

^{17 40} C.F.R. § 257.64.

¹⁸ 40 C.F.R. §§ 257.64(5), 257.101(b)(1) (surface impoundments), 257.101(d)(1) (landfills).

¹⁹ See Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016.

²⁰ See Fla. Admin. Code. R. 62-302.400(16)(b)(9) (2016) (classifying "all coastal waters and tidal creeks" within Citrus County as Class II waters).. The Surface Water Quality Criteria are designed to to "protect fish consumption, recreation and the propagation and maintenance of a health, well-balanced population of fish and wildlife." Fla. Admin. Code. R. 62-302-400(4) (2016). Florida has set Surface Water Quality Criteria).

²¹ U.S. Nuclear Regulatory Commission, Draft Environmental Impact Statement for Crystal River Unit 3, at 2-42
Water-related industries, such as commercial fishing and tourism, make up a large sector of the employment base in Citrus County.²² These sectors of the local economy "depend upon the resources of the coastal fisheries and the West Indian (Florida) manatee."²³ Over ninety species of fish have been identified near CREC.²⁴

Federally-listed threatened or endangered species in the vicinity of the CREC include, but are not limited to, the Gulf sturgeon, smalltooth sawfish, green turtle, hawksbill turtle, Kemp's ridley turtle, leatherback turtle, loggerhead turtle, the American alligator, the wood stork, the bald eagle, and the Florida manatee.²⁵ Manatees are known to dwell in Crystal River effluent and intake canals during the spring and fall²⁶ and nearby Crystal River/Kings Bay, an Outstanding Florida Water, is the largest winter refuge for manatees on the Florida Gulf Coast.²⁷

As detailed in Exhibit 1, the CREC is located in one of the country's most unstable areas with 24 known sinkholes within a 5 mile distance. Indeed, coastal Citrus County is an active karst area with sandy sediment cover over limestone.²⁸ The near-surface limestone is deeply incised with solution channels and conduits that can cause additional sinkholes to form as surficial sands move into subsurface voids.²⁹ The permeable surficial sediments allow access to the shallow, unconfined aquifer below through solution cavities and along fractures. Groundwater at CREC flows towards Crystal Bay and the Gulf of Mexico via the seawater discharge canal, and tidal wetlands.

Wastewater from Units 4 and 5 includes runoff from coal, gypsum, and limestone storage handling areas and the Ash Landfill, overflow bottom ash sluice water, FGD wastewater, FGMC wastewater, and cooling tower blowdown. These wastewaters are combined and released into the seawater discharge canal, which connects the plant to Crystal Bay.

Bottom ash generated at CREC Units 4 and 5 is sluiced to handling tanks and dewatering bins, where bottom ash solids are separated out from the wastewater.³⁰ Overflow bottom ash

^{(2011) (}citing Florida Fish and Wildlife Conservation Commission (FWC, 2005)).).

²² See e.g., Tommy Thompson, *Time to Join the Crystal River Circus*, Florida Sportsman, February 1, 2006, *available at* <u>http://www.floridasportsman.com/2006/02/01/fishing_crystal_river_powerplant/</u>

²³ Citrus County Comprehensive Plan, Chapter 4, 4-13, October 28, 2014, *available at*

https://www.citrusbocc.com/plandev/landdev/comp-plan/chapter-4.pdf.,

²⁴ U.S. Nuclear Regulatory Commission, Draft Environmental Impact Statement for Crystal River Unit 3, at 2-5.

²⁵ Duke Energy Florida, Inc. Crystal River Unit 3 Post-Shutdown Decommissioning Activities Report, at 25 (Dec. 2013) *available at* <u>http://www.duke-energy.com/pdfs/3f1213-02_psdar.pdf</u>.

²⁶ See Citrus County Comprehensive Plan, Chapter 13, October 28, 2014, *available at* <u>https://www.citrusbocc.com/plandev/landdev/comp-plan/chapter-13.pdf.</u>

²⁷ Southwest Florida Water Management District, *Crystal River/Kings Bay, Citrus County* <u>https://www.swfwmd.state.fl.us/springs/kings-bay/</u>

²⁸ See Exhibit 1.

²⁹ *Id.* at 4 (citing Dames and Moore 1994).

³⁰ Duke Energy Florida, Ash Storage/Disposal Area Operations Plan at 2, 5 (Dec. 2013); Duke Energy Florida, Response to Request for Additional Information, May 20, 2016 (hereinafter "RAI #2").

wastewater from the dewatering bins is permitted to flow through internal Outfall I-CH0, which is released through the main discharge canal at Outfall D-001 to Crystal Bay.

Fly ash and bottom ash solids from Units 4 and 5 are taken to CREC's Ash Landfill for disposal or storage. The 62-acre, unlined Ash Landfill began operating alongside Units 4 and 5 in the 1980's and receives a mixture of bottom ash, fly ash, gypsum, pyrites, FGD blowdown solids, mill rejects, and other CCR. ³¹ The Ash Landfill is unlined³² as well as uncovered,³³ allowing water, such as precipitation, to enter and mix with the wastes inside, and subsequently leach CCR contaminants into the groundwater beneath the Ash Landfill, and then into the runoff collection system, the seawater discharge canal, and the waters of Crystal Bay.

Units 4 and 5 use a wet scrubber system for sulfur dioxide removal, which produces FGD wastewater as a byproduct. This wastewater is discharged to the plant's FGD Blowdown Ponds, two 1.5- and 4.5-acre solids settling ponds that became operational in 2010.³⁴ Solids are settled out in the FGD Blowdown Ponds and the remaining liquid is pumped to CREC's unlined Percolation Ponds to be absorbed into groundwater. FGMC wastewater is generated via the plant's mercury control system and is injected into the FGD absorber before also being discharged to the Percolation Ponds.³⁵ Gypsum solids are conveyed to the concrete-lined Gypsum Storage Pad and stored before disposal in the Ash Landfill or transport offsite for sale.

LEGAL REQUIREMENTS

The wastewater and solid waste byproducts of burning coal at CREC fall under two new U.S. Environmental Protection Agency ("EPA") rules: the ELGs and the CCR Rule. These rules advance vital public health and environmental safeguards against the toxic metals and other pollutants found in CREC's waste streams.

CREC Units 4 and 5 discharge wastewater into Crystal Bay and are therefore required, pursuant to section 402 of the Clean Water Act ("CWA"), to obtain a NPDES permit. In enacting the CWA, Congress established as a national goal the elimination of all discharges of pollution into waters of the United States.³⁶ To this end, the Act's implementing regulations establish the NPDES permitting program. Under the program, no pollutant may be discharged from any "point source" without a permit, and failure to comply with such a permit constitutes a violation of the CWA.³⁷ The CWA defines a "point source" as "any discernible, confined and

³¹ Ash Storage/Disposal Area CCR Landfill Annual Inspection Report, December 2015; Florida Department of Environmental Protection Inspection Report, July 28, 2015.

³² The 62-acre landfill is unlined with the exception of a 5.5-acre horizontal expansion in June 2010 which used a geosynthetic clay liner. RAI #2.

³³ Approximately 11 acres of the landfill has been covered with a geosynthetic clay liner, 24-inches of protective soil cover, and sod. *Id.*

 ³⁴ Record Documentation of Units 4 and 5 FGD Blowdown Ponds Construction Quality Assurance (January 2010).
 ³⁵ RAI #2.1

³⁶ 33 U.S.C. § 1251(a)(1).

³⁷ 33 U.S.C. §§ 1311(a) and 1342(a); 40 C.F.R. § 122.41(a).

discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, [or] container ... from which pollutants are or may be discharged."³⁸

The CWA authorizes EPA to establish national, technology-based effluent limitations guidelines for discharges from categories of point sources, and requires that NPDES permits include effluent limits based on the performance achievable through the use of statutorily-prescribed levels of technology that "will result in reasonable further progress toward the national goal of eliminating the discharge of all pollutants."³⁹

The ELGs became effective on January 4, 2016, and must be included in NPDES permits for such generators going forward. The ELGs impose technology-based effluent limitations—reflecting decades of advances in water quality science and control technology—on discharges of several common types of effluent (i.e., waste streams) from coal-burning power plants, including fly ash and bottom ash transport waters and wastewater from FGD and FGMC systems.

Under the CWA, it is the responsibility of state permitting authorities, such as DEP, to "incorporate the ELGs into NPDES permits as a floor or a minimum level of control."⁴⁰ November 1, 2018, is the default deadline for all coal-burning⁴¹ power plants across the country.⁴² Because we submitted comments to you in February detailing DEP's implementation responsibilities, we will not repeat ourselves here, but instead incorporate those comments by reference.⁴³

EPA's CCR Rule, effective October 19, 2015, establishes national minimum requirements for the safe disposal of coal combustion residuals, or CCR, the solid waste byproducts of burning coal, commonly known as "coal ash." CCR contain toxic metals that for years have contaminated groundwater and put public drinking water supplies and surface waters at risk.⁴⁴ The CCR Rule advances public health and environmental safeguards, including enhanced groundwater monitoring, location restrictions for siting CCR waste facilities, liner and leachate collection requirements, and corrective action for cleaning up groundwater contamination.

Unlike the ELG requirements for direct dischargers, the CCR rule is self-implementing. EPA explains: "The federal standards apply directly to the facility (are self-implementing) and facilities are directly responsible for ensuring that their operations comply with these

³⁸ 33 U.S.C. § 1362(4).

³⁹ 33 U.S.C. § 1311(b)(2)(A)(i), see also § 1311(b)(1)(A);)

⁴⁰ 80 Fed. Reg. at 67,882.

⁴¹ *Id.* at 67,839, n. 1 ("power plants covered by the ELGs use nuclear or fossil fuels, such as <u>coal</u>, oil, or natural gas, to heat water in boilers, which generate steam." [emphasis added]).

⁴² See, e.g., 40 C.F.R. § 423.13(g)(1)(i).

⁴³ Letter from Sierra Club et al. to Supervisor Marc Harris, Power Plant NPDES Permitting, DEP Industrial Wastewater Section Re: *Bringing Florida Coal Plants Into Compliance With The New Effluent Limitations Guidelines*, (Feb. 29, 2016), *available at* <u>http://blog.cleanenergy.org/files/2016/05/2016-02-29-Letter-re-Water-Side-Reqts-for-Fla-Coal-Plants-vfin.pdf</u>.

⁴⁴ 80 Fed. Reg. 21,396; *see also* 80 Fed. Reg. 21,326: EPA identified 157 cases of proven or potential groundwater contamination from CCR in states across the nation.

requirements."⁴⁵ To ensure full and timely compliance with the CCR Rule, states can adopt the applicable standards in NPDES permits.⁴⁶ Likewise, states and citizens can enforce the federal standards under the citizen suit authority of the Resource Conservation and Recovery Act ("RCRA").

COMMENTS

In this section, we explain the changes DEP should make as it finalizes Permit No. FL0036366 to bring the CREC into compliance with the applicable public health and safety standards in the ELGs and the CCR Rule.

A. DEP Should Require Compliance with a Zero Discharge Standard for Bottom Ash Wastewater No Later Than November 1, 2018

Under the ELGs, the BAT standard for bottom ash wastewater is zero discharge. DEP should require the CREC to meet this zero discharge standard by November 1, 2018. As Dr. Sahu explains in his enclosed report, and we repeat here for emphasis, nothing in the permitting record justifies any later compliance deadline; in fact, the record shows that DEF is well-positioned to meet the default compliance deadline:

- DEF has already spent more than three years planning to convert to dry bottom ash handling at the CREC to comply with the ELGs, and has not documented any possible reason for needing additional time to plan, nor for why planning was slated to begin in June 2016 in the proposed schedule. DEF admits that compliance options are readily available.
- Duke Energy has publicly reported projected costs for ELG compliance at CREC Units 4 and 5 since at least 2014, which required conceptual or detailed engineering evaluations and studies in order to develop cost estimates. An additional 6 months for budget approval is unnecessary.

In fact, while DEF has long anticipated a "late 2018" compliance deadline,⁴⁷ DEF proposed almost five more years—to December 31, 2023—to reach compliance—without any justification for such a huge delay.⁴⁸ DEP should reject DEF's unsubstantiated and improper extension request.

As Dr. Sahu explains, it is clear that a November 1, 2018, compliance deadline for the BAT standard is readily achievable: most of the planning is finished, procurement should take little to no time and DEF admits construction takes 18 months.

⁴⁵ 80 Fed. Reg. 21,311.

⁴⁶ Additionally, states can continue to enforce state regulations under their independent state enforcement authority.

⁴⁷ Exhibit 1.

⁴⁸ Response to RAI 2, Attachment 1

Dr. Sahu concludes that Units 4 and 5 can convert to dry bottom ash handling in approximately 27 to 30 months, instead of the 44 months projected by DEF, reaching compliance by August to November 2018 at the latest.

Indeed, EPA's rulemaking record and comments from the Utility Water Act Group ("UWAG")⁴⁹ show that, depending on the scope of the required conversions (a.k.a., retrofits) at a particular coal plant, industry itself projects that the total time needed for bottom ash system retrofits ranges from 27 to 36 months, from the start of conceptual engineering to final commissioning.⁵⁰

At Duke Energy's own Mayo Plant in North Carolina, a wet-to-dry bottom ash handling system conversion was completed in under a year and a half.⁵¹ At the South Carolina Electric & Gas Company Wateree plant, for example, conversion to a closed-loop bottom ash handling system was completed in two and a half years.⁵² Conversion to a closed-loop bottom ash handling system was completed in two and a half years at the South Carolina Electric & Gas Company Wateree plant.⁵³ In 2010, the BL England Station retrofitted a recycle system on two coal burning units (one is 125-MW, the other is 155-MW) as well as a 170-MW oil-burning unit in less than two years from award of contract to operation of the new system.⁵⁴

Delaying compliance with the zero discharge standard for bottom ash wastewater beyond November 1, 2018, is unnecessary and puts public and environmental health at risk. Bottom ash wastewaters are known to contain a number of toxic metals in both suspended and dissolved form, including arsenic, cadmium, chromium, copper, iron, lead, mercury, selenium, and zinc.⁵⁵ In one example of the public and environmental health threats posed by CCR waste, EPA estimates that reductions in arsenic loadings from the final ELGs will reduce cancer risks to humans that consume fish exposed to steam electric power plant discharges—such as those caught in Crystal Bay.⁵⁶ Against this backdrop, DEP has all the more reason to require CREC to comply with the zero discharge standard by the November 1, 2018, deadline.⁵⁷

⁴⁹ Duke Energy is a UWAG member.

⁵⁰ Utility Water Act Group, Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (Sept. 30, 2013), Attach. 11: Retrofitting Dry Bottom Ash Handling.

⁵¹ See DEF Progress, Inc., Mayo Steam Electric Generating Plant, Quarterly Progress Report (January – March 2015) ("Dry bottom ash handling system began construction on December 14, 2012. As of March 31, 2014, construction of this system was 100% complete.").

⁵² DCN SE03779. Final Notes from Site Visit at South Carolina Electric & Gas Company's Wateree Station on January 24, 2013, *available at* http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OW-2009-0819-1917.

⁵³ See Final Notes from Site Visit at South Carolina Electric & Gas Company's Wateree Station on January 24, 2013, EPA-HQ-OW-2009-0819-1917, at 2. Check, from SELC comments, change text

⁵⁴ Dennis Del Vecchio and Robert G. Walsh, Wet to Dry Bottom Ash Disposal Conversion Project - BL England Station, Power-Gen, December 2011, February 2008 - February 2010.

⁵⁵ See e.g., U.S. EPA, Steam Electric Power Generating Point Source Category: Final Detailed Study Report, EPA 821-R-09-008, 3-19 (Oct. 2009), (hereinafter "EPA Detailed Study"); U.S. EPA, Development Document for Final Effluent Limitations Guidelines, New Source Performance Standards, and Pretreatment Standards for the Steam Electric Point Source Category, Table V-33 (Nov. 1982).

⁵⁶ 80 Fed. Reg. 67,874 (Nov. 8, 2015).

⁵⁷ 80 Fed. Reg. at 67,840-41.

B. The ELGs Apply to FGD Wastewater and FGMC Wastewater From Units 4 and 5, Which Discharge to Crystal Bay and the Gulf of Mexico via Hydrologically Connected Groundwater

Steam electric power plants must meet strict new standards in EPA's revised ELGs for contaminants in FGD wastewater—including arsenic, mercury, selenium, and nitrate/nitrite— and a zero discharge standard for FGMC wastewater. Because Unit 4 and 5's FGD and FGMC wastewaters discharge to waters of the United States, these waste streams must meet the standards in EPA's revised ELGs, and DEP must include permit limits in the renewed NPDES permit for CREC Units 4 and 5.

As Dr. Stewart explains in his enclosed report, contaminants from the unlined Percolation Ponds travel through the aquifer into Crystal Bay. FGD and FGMC wastewaters from Units 4 and 5 are thus discharged to the Percolation Ponds and absorbed into groundwater, as DEP is already aware.⁵⁸ The Percolation Ponds are unlined, in direct communication with the Upper Floridan aquifer, and connected to Crystal Bay and the Gulf of Mexico.⁵⁹ The Percolation Ponds recharge the shallow groundwater aquifer, which conveys pollutants into the seawater discharge canal, tidal wetlands, and Crystal Bay.⁶⁰

The Percolation Ponds and groundwater are hydrologically connected to "waters of the United States"—that is, Crystal Bay and the Gulf of Mexico—and therefore, by discharging pollutants into the Percolation Ponds, DEF is discharging to waters of the United States *via* the Ponds and the groundwater. The Percolation Ponds and groundwater are conduits to waters of the United States. Discharging the FGD and FGMC wastewater to the Percolation Ponds puts these waste streams under the jurisdiction of the CWA, and the Units 4 and 5 NPDES Permit, because the wastewaters, and pollutants, migrate from the pond directly into Crystal Bay through an underground "conveyance" or "conduit."⁶¹

When groundwater is a conduit for pollutants, CWA liability may attach to a discharge to that groundwater.⁶² "[I]t would hardly make sense for the CWA to encompass a polluter who discharges pollutants via a pipe running from the factory directly to the riverbank, but not a polluter who dumps the same pollutants into a man-made settling basin some distance short of the river and then allows the pollutants to seep into the river via the groundwater."⁶³ EPA has asserted that its authority under the CWA extends to hydrologically connected groundwater.⁶⁴

⁵⁸ See e.g., Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016; RAI #2,

⁵⁹ Exhibit 1 at 9.

⁶⁰ Id.

^{61 33} U.S.C. § 1362(14).

⁶² See Haw. Wildlife Fund v. Cnty. of Maui, 24 F. Supp. 3d 980, 996 (D. Haw. 2014).

⁶³ N. Cal. Riverwatch v. Mercer Fraser Co., No. C-04-4620 SC, 2005 U.S. Dist. LEXIS 42997, *7-*8 (N.D. Cal. Sep. 1, 2005).

⁶⁴ 66 Fed. Reg. 2960, 3015 (Jan. 12, 2001); 73 Fed. Reg. 70,418, 70,420 (Nov. 20, 2008); 55 Fed. Reg. 47990, 47997 (col. 3) (Nov. 16, 1990)

⁹²

The courts agree and have held, definitively, that the CWA covers groundwater that is hydrologically connected to waters of the United States. ⁶⁵ Eleventh Circuit jurisprudence, governing Florida, also suggests that CWA jurisdiction extends to discharges like those to CREC Percolation Ponds.⁶⁶

In sum, the FGD and FGMC wastewaters from Units 4 and 5 are discharged to surface waters *through* groundwater, and since the groundwater under the Percolation Ponds is directly hydrologically connected to surface water, discharges to the percolation ponds are a discharge to waters of the United States and must be regulated under the CWA. Therefore— just as DEP has included ELG limits for leachate that migrates through groundwater to the runoff collection system (see Section E below)—the ELGs apply to discharges of FGD and FGMC wastewaters and must be included in the revised NPDES permit.

C. DEP Should Require Compliance with a Zero Discharge Standard for FGMC Wastewater No Later Than November 1, 2018

Under the ELGs, FGMC wastewater at CREC must be monitored and subject to new effluent limits. Effective immediately, this discharge is subject to a BPT TSS effluent limit of 100/30 mg/L (daily max./30 day avg.) and oil and grease effluent limit of 20/15 mg/L (daily max./30 day avg.) and after November 1, 2018, a zero discharge standard applies.⁶⁷

As explained above in Section B, FGMC wastewater at the plant is discharged to waters of the United States—Crystal Bay and the Gulf of Mexico—through hydrologically connected groundwater and must be regulated under the ELGs. Although the FGMC wastewater combines with FGD wastewater at CREC Units 4 and 5, the zero discharge standard still applies: "Whenever flue gas mercury control wastewater is used in any other plant process or is sent to a treatment system at the plant, the resulting effluent must comply with the [zero] discharge limitation in this paragraph."⁶⁸

The final permit therefore must include BPT limits for FGMC wastewater until a zero discharge BAT standard applies after November 1, 2018. Again, the revised ELGs apply starting

⁶⁸ 40 C.F.R. § 423.13 (i)(1)(i).

⁶⁵ See e.g., Waterkeeper Alliance, Inc. v. U.S. EPA, 399 F.3d 486, 514-515 (2d Cir. 2005) (upholding EPA's requirements for the discharge of pollutants to surface water via groundwater to be regulated, "as necessary, on a case-by-case basis."); Dague v. City of Burlington, 935 F.2d 1343, 1347 & 1355 (2d Cir. 1991), rev'd in part on other grounds, 505 U.S. 557 (1992) (finding the city liable for allowing groundwater to flow through a landfill and into a pond and wetlands that were waters of the United States); U.S. Steel Corp. v. Train, 556 F.2d 822, 852 (7th Cir. 1977) (the CWA "authorizes EPA to regulate the disposal of pollutants into deep wells, at least when the regulation is undertaken in conjunction with limitations on the permittee's discharges into surface waters"), overruled on other grounds by City of West Chicago v. U.S. Nuclear Regulatory Comm'n, 701 F.2d 632, 644 (7th Cir. 1983).

⁶⁶ U.S. v Banks, 115 F.3d 916 (11th Cir. 1997) (District Court not clearly erroneous in deciding that wetlands are adjacent to a waterbody because of a hydrological connection where a hydrological connection is largely through groundwater and a surface flow only appears during storms); United States v. Tilton, 705 F.2d 429, 431 (11th Cir. 1983) (a hydrological connection exists when flowing mainly through groundwater, even where surface water only connects at extreme high tides such as in hurricanes).

⁶⁷ 40 C.F.R. § 423.13(l).

November 1, 2018, or "as soon as possible" based on a well-documented justification of a later date and DEP's consideration of certain factors enumerated in the final rule.

Until the zero discharge BAT standard is met, DEP should incorporate monitoring requirements for the FGMC wastewater into revised NPDES permit and Conditions of Certification ("COC"). To meet both monthly average and daily maximum limits, quarterly monitoring is wholly inadequate. A daily maximum limit cannot be effectively enforced with monitoring conducted on a monthly basis. Monitoring frequency should be daily in order to effectively enforce these limits to meet both monthly average and daily maximum limits for TSS and oil and grease. Sampling should be performed prior to mixing with the FGD wastewater.

D. DEP Must Require Compliance with New Limits on FGD Wastewater Pollutants No Later Than December 2018

DEP must include effluent limits for FGD wastewater in the revised NPDES permit. Effective immediately, this discharge is subject to a BPT TSS effluent limit of 100/30 mg/L (daily max./30 day avg.) and oil and grease effluent limit of 20/15 mg/L (daily max./30 day avg.).⁶⁹ After November 1, 2018, DEF must meet strict new BAT effluent limits for arsenic, mercury, selenium, and nitrate/nitrite for the untreated FGD wastewater that is discharged to the Percolation Pond and waters of the United States.⁷⁰ DEP must incorporate the ELGs for FGD wastewater into the revised NPDES permit, immediately apply BPT and monitoring requirements, and ensure that DEF meets the BAT standard by December 2018 or as soon as possible.

The revised ELGs set daily maximum and monthly average limits on arsenic, mercury, selenium, and nitrate/nitrite in discharges of FGD wastewater.⁷¹ These limits are based on technology using chemical precipitation and an anoxic/anaerobic fixed-film biological treatment system.⁷² The chemical precipitation achieves most of the mercury and arsenic reductions, while the biological reactor removes selenium and nitrogen and other dissolved heavy metals.

DEF is currently completing "construction of a new wastewater treatment system that will use chemical precipitation and a bioreactor" for treatment of FGD wastewater from Units 4 and 5 and will complete the project by December 2018.⁷³ DEF "evaluated several treatment options…and selected a strategy that uses a physical/chemical treatment system with a bioreactor treatment system to treat Flue Gas Desulfurization ("FGD") blowdown wastewater with discharge to surface water or percolation ponds."⁷⁴

^{69 40} C.F.R. § 423.12(b)(11).

⁷⁰ 40 C.F.R. § 423.13(g)(1)(i).

⁷¹ Id.

⁷² 80 Fed. Reg. at 67,850.

 ⁷³ Third Amendment to Consent Order, OGC No. 09-3463D, at ¶4; *see also* Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016 at Attachment 4 p.2.
 ⁷⁴ Duke Energy Florida's Petition for Approval of Environmental Cost Recovery True-Up and 2017 Environmental Cost Recovery Clause Form 42-SP at 7 (August 31, 2016). 07181-16, PSC ECRC filing

⁹⁴

In November 2011, DEP entered into a Consent Order⁷⁵ with the former CREC owner Progress Energy Florida ("PEF") following exceedances of groundwater standards for gross alpha standard, radium 226/228, and arsenic. In the third amendment to the Consent Order in March 2016, DEF agreed to complete construction of a new wastewater treatment system using chemical precipitation and a bioreactor for treating FGD wastewater by December 31, 2018.⁷⁶ Within 30 days following completion of the treatment system, DEF will remove all accumulated CCR from the FGD Blowdown Ponds.⁷⁷

The Consent Order constitutes an additional and separate legal obligation (from the ELGs) to complete construction of the FGD wastewater treatment system by December 2018. Nevertheless, DEP is required to include the new effluent limits in the revised NPDES and to ensure that DEF's new treatment system meets the federal BAT standards for arsenic, mercury, selenium, and nitrate/nitrite—which are not specified in the Consent Order— "as soon as possible beginning November 1, 2018."

It is imperative that DEP ensure that DEF meets this timeline and its legal obligations and begins operating the new system and treating toxic FGD wastewater by December 2018 at the latest. DEF is on its way to meeting these new standards and anticipated⁷⁸ meeting the revised ELG requirements for FGD wastewater, in addition to its Consent Order obligations.

Attachment H— Groundwater Monitoring, Operation, and Maintenance Requirements—of CREC COC authorizes DEF to discharge a variety of wastewaters, including FGD wastewater from Units 4 and 5, to the Percolation Ponds.⁷⁹ Quarterly reporting is required for FGD wastewater flows at sampling point EFF-2, the discharge pipe into the Percolation Ponds.⁸⁰ However, no limits are imposed on the FGD wastewater flows. DEP must incorporate monitoring requirements for arsenic, mercury, selenium, nitrate/nitrite, and TSS into the revised NPDES permit, as well as the COC. Monitoring should be required twice weekly. For final limits, where both monthly average and daily maximum limits are set, quarterly monitoring is wholly inadequate. A daily maximum limit cannot be effectively enforced with monitoring conducted on a monthly basis. Monitoring frequency should be daily to effectively enforce these limits.

E. Combustion Residual Leachate from the Ash Landfill is Subject to Technology and Water Quality Based Effluent Limits

⁷⁵ Consent Order, File No. 09-34652, Permit No. FLA016960, OGC File No. 09-3463 (Nov. 2011).

⁷⁶ Third Amendment to Consent Order, OGC No. 09-3463D ¶4 (March 22, 2016).

⁷⁷ Third Amendment to Consent Order, OGC No. 09-3463D ¶5 (March 22, 2016).

⁷⁸ Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016 at Attachment 4 p. 1.

⁷⁹ Florida Department of Environmental Protection, Conditions of Certification: Duke energy Florida Crystal River Energy Complex, PA 77-09R, Attachment H, April 29, 2016.

⁸⁰ Id.

Combustion residual leachate ("CRL") is now a separately regulated waste stream under the revised ELGs. Leachate from coal ash and other CCRs that are discharged to waters of the United States must be included in the NPDES permit and subject BPT limits in TSS and oil and grease, as well as technology and water quality based effluent limits.

CREC has no leachate collection system for the unlined Ash Landfill, and instead of being discharged to surface waters through a permitted outfall, most leachate seeps into the groundwater, as discussed further below in Section G and in Exhibit 1. The "majority of the coal combustion residual leachate is discharged to ground water"⁸¹ as "by design, the leachate generated in the [Ash Landfill] infiltrates to the groundwater underneath the [Ash Landfill]."⁸² EPA correctly notes that "[u]nlined impoundments and landfills usually do not collect leachate, which would allow the leachate to potentially migrate to nearby ground waters, drinking water wells, or surface waters."⁸³

Since groundwater beneath the Ash Landfill is hydrologically connected to surface waters, CRL wastewater discharging from the Ash Landfill to groundwater constitutes a discharge to waters of the United States. DEF's groundwater modeling shows that CRL from the unlined Ash Landfill at times flows towards portions of the runoff ditch at Units 4 and 5.⁸⁴ Following, DEP has incorporated new BPT limitations for oil and grease and TSS in the Draft Permit at monitoring well TWI-1R, in order to differentiate CRL from storm water collected in the runoff collection system.⁸⁵

Additionally, as described in Dr. Stewart's assessment, groundwater under the Ash Landfill "flows toward the west-southwest and discharges into the seawater discharge canal, and ultimately into Crystal Bay."⁸⁶ Indeed, monitoring data shows that toxic pollutants from CCR leachate⁸⁷—including arsenic, boron, manganese, molybdenum, selenium, and sulfate—are migrating from groundwater beneath the Ash Landfill and flowing to Crystal Bay.

Like CRL leachate that migrates through groundwater to the runoff collection system, and for the reasons articulated above in Section B for FGD and FGMC wastewater, the discharges of leachate to groundwater beneath the Ash Landfill and into the seawater discharge canal, and then Crystal Bay, are also subject to the CWA. The CWA prohibits the discharge of pollutants from a point source" — "any discernible, confined and discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, [or] container … from which pollutants are or may be discharged"⁸⁸—to waters of the United States, except as

⁸¹ Draft Permit at 12.

⁸² RAI #2 p. 9.

⁸³ 80 Fed. Reg. at 67,847.

⁸⁴ RAI #2.

⁸⁵ Draft Permit p. 12.

⁸⁶ Exhibit 1 at 6.

⁸⁷ See TDD Table 6-13. Pollutants of Concern – Combustion Residual Leachate.

⁸⁸ 33 U.S.C. § 1362(4); *see also, e.g.*, *Dague v. City of Burlington*, 935 F.2d 1343, 1347 & 1355 (2d Cir. 1991), rev'd in part on other grounds, 505 U.S. 557 (1992) (finding the city liable for allowing groundwater to flow through a landfill and into a pond and wetlands that were waters of the United States).

in compliance with a NPDES permit.⁸⁹ Thus, CRL from the Ash Landfill that is discharged to Crystal Bay via groundwater must be also regulated in the revised NPDES permit, and meet new BPT requirements as well as other water quality based requirements.

DEP must also conduct a reasonable potential analysis and determine whether additional water quality-based effluent limits ("WQBELs") are required for the CRL from the Ash Landfill, in order to protection of aquatic life and human health. After application of the most stringent treatment technologies available under the BAT standard, if a discharge causes or contributes, or has the reasonable potential to cause or contribute to a violation of water quality standards, the permitting agency must include any limits in the NPDES permits necessary to ensure that water quality standards (both narrative and numeric) are maintained and not violated.⁹⁰ EPA regulations require permitting authorities to characterize all effluents in order to determine the need for WQBELs in the permit.⁹¹

Ultimately, as explained below, the only way to prevent further contamination of ground and surface waters from the Ash Landfill is likely to remove all accumulated CCR from the Ash Landfill and decontaminate the site.

F. There is No Barrier Between the Unlined Ash Landfill and Percolation Ponds and the Underlying Groundwater, Allowing Toxic Coal Ash Contaminants to Pollute the Floridan Aquifer and Crystal Bay

The Ash Landfill and Percolation Ponds are unlined, with no protective barrier between toxic coal ash and wastewater and the underlying groundwater. Additionally, there is no intermediate confining unit between the highly permeable soils onsite and the Floridan aquifer, signifying an elevated risk of groundwater contamination. As a result, the toxic CCR waste and wastewaters that are disposed of in the unlined Ash Landfill and Percolation Ponds are in direct hydraulic connection with the Floridan aquifer and with groundwater draining into Crystal Bay.

Sierra Club retained one of the state's preeminent hydrogeologists, Dr. Mark Stewart, to evaluate conditions at CREC and application of the technical requirements in the CCR Rule. As explained in his accompanying report, Exhibit 1, the Floridan aquifer at CREC is unconfined and in direct hydraulic connection with the water table. The area is a recharge zone for the shallow aquifer. The underlying Floridan aquifer, one of the largest and most productive sources of fresh groundwater in the world,⁹² lies within a few feet of the land surface. Thus, the unlined Ash Landfill sits less than 5 feet from the water table in the Floridan aquifer.⁹³ Because the Ash

⁸⁹ Section 301(a) of the Clean Water Act, 33 U.S.C. § 1311(a).

⁹⁰ See 40 C.F.R. § 122.44(d). "[T]he permit must contain effluent limits" for any pollutant for which the state determines there is a reasonable potential for the pollutant to cause or contribute to a violation. *Id.* 40 C.F.R. § 122.44(d)(1)(iii); see also Am. Paper Inst. v. EPA, 996 F.2d 346, 350 (D.C. Cir. 1993); Waterkeeper Alliance, Inc. v. EPA, 399 F.3d 486, 502 (2d. Cir. 2005).

^{91 40} CFR § 122.44(d).

⁹² Exhibit 1 at 5 (citing Miller 1986).

⁹³ Exhibit 1..

Landfill and Percolation Pond are unlined, and because of the shallow, unconfined aquifer at CREC, these two facilities are in direct connection with underlying groundwater and Floridan aquifer.⁹⁴

To protect groundwater from contamination from CCR wastes, the CCR Rule prescribes (a) a distance of at least 5 feet between the base of facilities containing CCR and the uppermost aquifer, or (b) other measures that eliminate the hydraulic connection between the base and the uppermost aquifer—safety standards that the Ash Landfill, a CCR landfill⁹⁵, does not meet. CCR surface impoundments and new or expanded landfills must be constructed with a base that is located no less than five feet above the upper limit of the uppermost aquifer, or must demonstrate that there will not be an intermittent, recurring, or sustained hydraulic connection between any portion of the base of the CCR unit and the uppermost aquifer due to normal fluctuations in groundwater elevations (including the seasonal high water table).⁹⁶ While the Ash Landfill is exempt from this common-sense restriction as an "existing landfill"—although any future expansions and new facilities would not be—and the Percolation Ponds do not fall under the CCR Rule,⁹⁷ it is clear why these safety standards have been promulgated and that the close proximity of the unlined facilities to the aquifer are contaminating the Floridan aquifer and Crystal Bay.

Groundwater monitoring data showing contamination at the unlined Ash Landfill and Percolation Pond are further evidence of a hydraulic connection between the unlined Ash Landfill and the underlying aquifer. Groundwater pollution at the site, as described next in Section G, indicates that the Ash Landfill is in direct hydraulic connection with a highly permeable fracture zone in the Upper Floridan aquifer and that toxic contaminants are leaching from the Ash Landfill, as well as the Percolation Ponds, into the groundwater beneath, and moving towards Crystal Bay.

G. The Unlined Ash Landfill and Percolation Ponds Are Leaching Coal Ash Contaminants Into Groundwater and Crystal Bay

Groundwater contamination from toxic coal ash contaminants has been repeatedly documented at wells downgradient from the Ash Landfill. In fact, data from DEF's own groundwater monitoring wells downgradient of the unlined Ash Landfill have consistently shown contamination at levels that far exceed background levels and federal, state, and permit limits.⁹⁸ This threatens the Floridan aquifer and waters of Crystal Bay and the Gulf of Mexico.

⁹⁴ Exhibit 1.

⁹⁵ The CREC Ash Landfill is an "existing CCR landfill," subject to regulation under the CCR Rule. It is an "area of land or an excavation that receives CCR and which is not a surface impoundment, an underground injection well, a salt dome formation, a salt bed formation, an underground or surface mine, or a cave" that received CCR both before and after October 19, 2015. 40 C.F.R. § 257.53.

^{96 40} C.F.R. § 257.60.

⁹⁷ See 40 C.F.R. § 257.53.

⁹⁸ See Florida Department of Environmental Protection, Conditions of Certification: Duke energy Florida Crystal River Energy Complex, PA 77-09R, Attachment H, April 29, 2016; 40 C.F.R. §§ 141.62 and 141.66; Fla. Admin. Code. R. 62-520.420 (2016).

Wells downgradient from the unlined Ash Landfill have regularly exceeded regulatory for toxic coal ash contaminants—arsenic, boron, manganese, molybdenum, selenium, sulfate, and thallium—since 2012.⁹⁹ Levels of arsenic, boron, manganese, molybdenum, and sulfate, in particular, have trended upward since that time and continue to exceed protective groundwater standards. Concentration of arsenic at wells downgradient from the Ash Landfill are *five times* higher than at wells upgradient from the facility.

The presence of these common coal ash contaminants at monitoring wells downgradient from the unlined Ash Landfill, in combination with groundwater flow direction at the site and high permeability conduits, is, in Dr. Stewart's view, "overwhelming evidence" that contaminants have leached from the CCR materials have reached the water table and the Floridan aquifer.¹⁰⁰

Contaminants from the unlined Percolation Ponds are also being absorbed to groundwater, which flows towards the Gulf of Mexico. Arsenic in groundwater near the ponds has been associated with the FGD wastewater that is discharged to the ponds, thus driving the installation of the new FGD wastewater treatment system.¹⁰¹

DEP is currently investigating groundwater contamination from the Ash Landfill.¹⁰²A July 2015 DEP inspection noted adverse impacts to water quality from the operation of the Ash Landfill and that "[g]roundwater trending data for background and intermediate groundwater monitoring wells indicates impacts to groundwater, specifically for Arsenic, Boron, Manganese, and Molybdenum."¹⁰³ Steps have been taken to address contamination at the Percolation Ponds under CREC's November 2011 Consent Order.¹⁰⁴

While alarming, the groundwater contamination at the Ash Landfill is not at all surprising given that the facility is unlined and lacks a protective barrier, that the CCR materials within it are in direct hydraulic connection with the Floridan aquifer, and given the shallow, unconfined aquifer. In fact, DEP predicted that serious groundwater contamination would occur from the operation of the Ash Landfill:

⁹⁹ Exhibit 1; Florida Department of Environmental Protection ("DEP"), 2015. Groundwater Review, WAVS UD 97667, Amaury Betancourt, Nov. 30, 2015; Florida Department of Environmental Protection ("DEP"), 2016. FDEP Automated Data Evaluation. Duke Energy (FKA PEF) Crystal River Energy Complex. February 1, 2016 ¹⁰⁰ Exhibit 1 at 9.

¹⁰¹ Geosyntec, 2013. Arsenic and radionuclide plan of study addendum, Crystal River Energy Complex, Crystal River, Florida, Rpt. No. FR2061/03, April 2013; Consent Order No. 09-34652. This groundwater contamination (under NPDES Permit No. FLA016960) remains unresolved, five years later. Further review of arsenic contamination is required, but not until December 31, 2017, and a plan to evaluate arsenic impacts on downgradient surface waters is required by June 30, 2018. Full compliance with arsenic limits is required by December 31, 2019. DEP should reopen NPDES Permit No. FL0036366 pending results of the required studies and strictly enforce corrective action to clean up groundwater contamination at the CREC.

¹⁰² Email from Amaury Betancourt, P.E., Florida Department of Environmental Protection to Mr. Bob Stafford, Duke Energy, February 15, 2016.

¹⁰³ See Florida Department of Environmental Protection Inspection Report, July 28, 2015.

¹⁰⁴ Consent Order No. 09-34652.

"The highly transmissive characteristic of the shallow aquifer zone should provide and environment for the rapid dispersion of leachate which might infiltrate from the ash disposal site into the shallow aquifer."...

[Former CREC owner and applicant] FPC's application demonstrates succinctly that point at which such economico-politico maneuvering leads to very serious consequences when 1000 tons per day of truly hazardous wastes, generated each day that Units 4 and 5 would operate (for 30 years or more), would be dumped, for all practical purposes into the Floridan aquifer. ...

Thus leachate from the proposed ash disposal area can (on the basis of the data implicating the existing dump as a source of ground water pollution) be expected to flow into the Floridan aquifer at such rates that a number of WQ standards would be violated short term. (Perhaps many more violations would occur long term as pollutant activities build up on the ecosystem). Should the leachate move through existing or through induced Karst structures into deeper zones of the aquifer where hydraulic head may be reduced (or only appear to equal or even "slightly exceed" shallow depth heads by reason of statistically inadequate data or by greater <u>density</u> due to higher salinity or loading of leachate itself), then so much the worse for the Floridan aquifer.¹⁰⁵

As Dr. Stewart explains in his assessment, there is no adequate liner or natural barrier to prevent CCR constituents from seeping out of the Ash Landfill into the underlying aquifer and eventually into Crystal Bay and the Gulf of Mexico. Until DEF removes the existing CCR material from the Ash Landfill and decontaminates the site, it will continue to leach toxic CCR contaminants into ground and surface waters. Furthermore, as explained next in Section H, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated.

H. The CCR Rule Requires Corrective Action to Address the Groundwater Contamination from the Unlined Ash Landfill

Where coal ash contaminants from CCR units have leached into the environment in excess of federal regulatory limits, the CCR Rule requires corrective action to prevent further releases. Monitoring data at CREC show levels of arsenic, molybdenum, and thallium at wells downgradient from the Ash Landfill exceeding federal groundwater protection standards and triggering clean up requirements for DEF.

To ensure compliance with the CCR Rule and to prevent further releases of CCR constituents into Floridan waters, DEP should require DEF to immediately take action to remove the CCR that has accumulated and decontaminate the Ash Landfill.

¹⁰⁵ Ash Landfill Interoffice Memo at 3, 4, 7 (emphasis original).

Owners and operators of CCR units must install a system of groundwater monitoring wells and establish a monitoring program to detect the presence of hazardous constituents and other monitoring parameters from covered CCR units.¹⁰⁶ Where groundwater monitoring shows exceedances of groundwater protection standards¹⁰⁷ for Appendix IV constituents—including arsenic, molybdenum, and thallium—the owner or operator must initiate corrective action, retrofit, and/or close the unit.¹⁰⁸

For these Appendix IV CCR constituents of concern, "immediately upon detection of a release from a CCR unit" the owner/operator "must initiate an assessment of corrective measures to prevent further releases, to remediate any releases and to restore affected area [*sic*] to original conditions."¹⁰⁹ Then, the owner/operator must select and implement remedies certified by a qualified engineer to be consistent with the standards set out in the CCR Rule. Specifically, the "remedies must"

- (1) Be protective of human health and the environment;
- (2) Attain the groundwater protection standard as specified pursuant to §257.95(h);
- (3) Control the source(s) of releases so as to reduce or eliminate, to the maximum extent feasible, further releases of constituents in Appendix IV to this part into the environment;
- (4) Remove from the environment as much of the contaminated material that was released from the CCR unit as is feasible, taking into account factors such as avoiding inappropriate disturbance of sensitive ecosystems; and
- (5) Comply with standards for management of wastes as specified in $\S257.98(d)$.¹¹⁰

The requirement to "immediately" initiate an assessment of corrective measures is triggered by the detection of a release at any time after the effective date of the CCR Rule, October 19, 2015. This includes but is not limited to detection pursuant to a pre-existing groundwater monitoring program and/or the enhanced groundwater monitoring program that is required by the CCR Rule. The "zone of discharge" exemption to water quality standards under Florida law do not apply; "the point of compliance is the waste boundary" of CCR units.¹¹¹

¹⁰⁶ 40 C.F.R. § 257.94(a).

¹⁰⁷ Groundwater protection standards for Appendix IV constituents detected are based on either (1) the maximum contaminant limit ("MCL") established at 40 C.F.R. \S 141.62 and 141.66; or (2) the background concentration for the constituent, where there is no MCL or where the background concentrations are higher than the MCL. 40 C.F.R. \S 257.95(h).

¹⁰⁸ 40 C.F.R. §§ 257.95(g)(5); 257.101(a).

¹⁰⁹ 40 C.F.R. § 257.96.

¹¹⁰ 40 C.F.R. § 257.97.

¹¹¹ EPA, Comment Summary and Response Document, Docket #EPA-HQ-RCRA-2009-0640, Volume 9: Groundwater and Corrective Action at 47; *see also* 40 C.F.R. § 257.53 (defining "waste boundary"); § 257.91 (requiring groundwater

¹⁰¹

Groundwater monitoring data for the Ash Landfill following October 19, 2015, show exceedances of groundwater protection standards¹¹² for arsenic, molybdenum, and thallium, all Appendix IV constituents, at wells downgradient from the Ash Landfill, an existing CCR landfill under the CCR Rule. With this knowledge, DEF is obligated to immediately begin an assessment of corrective measures and implementation of appropriate remedies. To meet the corrective action requirements in the CCR Rule, and to "eliminate, to the maximum extent feasible, further releases of constituents," Dr. Stewart recommends ceasing onsite CCR storage and disposal, which can exacerbate the ongoing contamination problem. The only way to effectively prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

I. CREC is Located in Sinkhole-Prone Karst Terrain, Putting Ground and Surface Water Resources at (Further) Risk and Requiring Compliance with the CCR Rule's Location Restriction for Unstable Areas

Coastal Citrus County is an active karst area, marked by limestone and under the influence of sinkholes. As detailed in Dr. Stewart's assessment, the onsite and local hydrogeological conditions make CREC an inherently unstable area, under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles.

Most sinkholes in the region are cover subsidence sinkholes, whereby loose surficial sands migrate downward into solution cavities in the limestone and which can occur either slowly or abruptly. Because the Floridan aquifer is at or near land surface at CREC, sinkholes of any size would allow the movement materials under the CCR landfill into the voids, depressions, and caverns underneath, allowing materials, such as CCR waste in the Ash Landfill, to come into direct contact with the limestones and groundwater of the Floridan aquifer.

DEP is aware of the unstable nature of CREC and accompanying risks to ground and surface waters from the sinkhole-marked terrain. For example, in a staff analysis, DEP described CREC as "characterized by sinkholes and flowing springs" and concluded that:

Due to the nature of the geologic formation under this area there <u>will always be a chance</u> of a sinkhole forming under the plant or its related facilities....

It is not apparent that FPC has adequately considered the impact that future solution cavities may have on the operation of the coal piles, the ash disposal landfill, and related ditches. Acidic leachates can hasten formulation of solution cavities which could result in

monitoring at the waste boundary); § 257.94 (requiring enhanced groundwater monitoring for detected increases in certain CCR constituents at the waste boundary).

¹¹² There is no MCL for molybdenum; instead the groundwater protection standard is the background level. A background well (MWB-30R) at the CREC shows molybdenum levels of 18 mg/L. In contrast, the intermediate monitoring well and temporary monitoring wells around the Ash Landfill have exhibited molybdenum levels ranging from 44.5 - 135 mg/L—*seven times higher* than background levels.

subsidence of the land surface and allow for rapid contamination of ground and surface waters.¹¹³

Later, DEP rightly questioned the sensibility of locating a coal ash landfill at CREC:

Already a piece of heavy machinery has fallen into a sinkhole on site which collapsed beneath the weight of the machine. What would be the effect of the much greater loading due to 60 or more feet of stacked ash materials spread over some 100 acres? Even if a massive collapse did not take place, allowing direct introduction of the wastes into the aquifer, [studies] clearly indicate the high permeability of the upper ...¹¹⁴

There is copious evidence, as documented in Dr. Stewart's assessment, DEP records¹¹⁵, and other sources, showing sinkhole activity at and around CREC. There can be no question that CREC is in unstable, sinkhole terrain and that, as described next in Sections J and K, CREC cannot meet CCR Rule's safety standards for onsite storage and disposal.

J. After April 19, 2019, the CCR Rule Prohibits Adding—Even On a Temporary Basis—CCR To CCR Units in Unstable Areas, Such As Florida's Karst Terrain, Unless a Qualified Engineer Can Certify That it is Safe To Do So

After April 19, 2019, the CCR Rule prohibits adding, even on a temporary basis, CCR to CCR units in unstable areas, such as Florida's karst terrain, unless a qualified engineer can certify that it is safe to do so by October 17, 2018.¹¹⁶ Specifically, this is a certification "that recognized and generally accepted good engineering practices have been incorporated into the design of the CCR unit to ensure that the integrity of the structural components of the CCR unit will not be disrupted."¹¹⁷ This location restriction applies to all existing and new CCR units.

EPA defines unstable areas as:

a location that is susceptible to natural or human-induced events or forces capable of impairing the integrity, including structural components of some or all of the CCR unit that are responsible for preventing releases from such unit. Unstable areas can include poor foundation conditions, areas susceptible to mass movements, and <u>karst terrains</u>.¹¹⁸

¹¹³ "1978 Staff Analysis, at 44, (STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION, ELECTRIC POWER PLANT SITE CERTIFICATION REVIEW FOR FLORIDA POWER CORPORATION CRYSTAL RIVER UNITS 4 AND 5, CASE NO. PA 77-09, STAFF ANALYSIS. September 15, 1978) (emphasis added).

¹¹⁴ Ash Landfill Interoffice Memo at 4.

¹¹⁵ Florida Department of Environmental Protection, Conditions of Certification: Duke energy Florida Crystal River Energy Complex, PA 77-09R, Attachment H, April 29, 2016;; Ash Landfill Interoffice Memo; 1978 Staff Analysis; Terry Witt, Citrus County Chronicle, July 23, 2007 and July 30, 2007 articles, *in* "Proposed Haul Road Letter"; FGD Blowdown bond 2010 report.

¹¹⁶ 40 C.F.R. §§ 257.101(b)(1) and 257.101(d)(1).

¹¹⁷ 40 C.F.R. § 257.64(a).

¹¹⁸ 40 C.F.R. § 257.53.

"Structural components" are defined as:

liners, leachate collection and removal systems, final covers, run-on and run-off systems, inflow design flood control systems, and any other component used in the construction and operation of the CCR unit that is necessary to ensure the integrity of the unit and that the contents of the unit are not released into the environment."¹¹⁹

In the final CCR Rule, EPA enumerates safety factors that should be addressed in the certification of CCR units in Florida's karst terrain:

For areas where the solution-weathered limestone is close to the surface (<u>e.g., Florida</u>) recognized and generally accepted good engineering practices dictate that there must be <u>no conduits beneath the CCR unit that allow piping of groundwater into the karst</u> aquifer, or shallow caves that could cause sudden collapse of the unit foundation. ...

Karst hydrogeology is complex, since contaminant flows can occur along paths and networks that are discreet and tortuous, and <u>groundwater monitoring wells must be</u> capable of detecting any contaminants released from the CCR unit into the karst aquifer. ...

Therefore, the owner or operator will need to ensure, with verification by a qualified professional engineer, that monitoring wells installed in accordance with § 257.91 will intercept these pathways. Verification will usually necessitate the use of tracers to track groundwater flow towards offsite seeps or springs from the uppermost aquifer beneath the facility. Any engineered solution employed to mitigate weak ground strength in karst areas must be able to prevent the kind of foundation collapse and settlement that could lead to sudden release to the environment of CCR with its toxic constituents and associated leachate. ...

However, such engineered solutions are complex and costly, and the best protection is not to site CCR landfills and surface impoundments in karst areas.¹²⁰

In short, this safety certification is a tall order in Florida's karst terrain. Elsewhere in the rulemaking docket, EPA noted that it might even be "impossible" to obtain the safety certification for a CCR unit that has already been constructed without adequate safeguards.¹²¹

These safety standards were not incorporated into the design of the Ash Landfill when it was built, as discussed in Dr. Stewart's assessment. The Ash Landfill does not have structural reinforcements nor a liner that could help prevent movement of CCR materials into the

¹¹⁹ Id.

¹²⁰ 80 Fed. Reg. 21,368 (emphasis added).

¹²¹ U.S. EPA, Comment Summary and Response Document, Volume 4: Location Restrictions, Docket # EPA-HQ-RCRA-2009-0640, December 2014, *available at* http://goo.gl/QVAXRi.

¹⁰⁴

Floridan aquifer. Dr. Stewart explains that certain factors at the Ash Landfill even increase the risk of limestone dissolution and sudden collapse, such as including having no impermeable liner; having no cover to exclude precipitation from the exposed CCR waste; and CCR accumulating and increasing the static load on the underlying, unstable soils.

Moreover, the Ash Landfill cannot effectively, nor economically, be retrofitted using existing technologies to meet the CCR Rule's safety standards: it would be nearly impossible to ensure that all conduits, voids, and caves beneath the Ash Landfill were had been detected and intercepted. Attempting a retrofit of the Ash Landfill now could even trigger a sinkhole collapse.

CREC FGD Blowdown Ponds and Gypsum Storage Pad also lie on unstable karst terrain and a qualified professional engineer must make a demonstration showing "that recognized and generally accepted good engineering practices have been incorporated" into the design of these units by October 17, 2018 in order for them to continue operation. Although these units are at least lined, providing some measure of protection unlike the Ash Landfill, if a sinkhole were to rupture the liners or pipes at the FGD Blowdown Ponds, for example, the CCR wastes would be released into the Floridan aquifer, and flow into the seawater discharge canal, tidal wetlands, and Crystal Bay.

DEF reports that a preliminary assessment of the stability at the Ash Landfill has been performed and that the "preliminary conclusion is no karst remediation will be required."¹²² This conclusion seems remarkable given the geological characteristics and history of the region and CREC site, as encapsulated above in Section I and in Dr. Stewart's review. Regardless of this conclusion, however a thorough evaluation must still be completed under the CCR Rule.

The CCR Rule location restriction and safety factors are designed to protect public waters from the risks of sinkhole and unstable terrain. To comply with federal regulations and protect the Floridan aquifer and waters of Crystal Bay, DEP must ensure that DEF completes the required engineering certifications. Because CREC's CCR units cannot be certified as safe under the CCR Rule, DEF will have to change its current practices of onsite CCR storage and disposal by the April 19, 2019 deadline in the CCR Rule.

K. DEP Should Extend The Proposed Schedule for Permit Issuance To Allow For Meaningful Consideration of Public Comments

Finally, we urge DEP to revise its own proposed schedule for permit issuance to allow for meaningful consideration of and response to public comments. Under the proposed schedule,¹²³ DEP would submit the proposed permit to EPA on September 30th, only *one day* after the close of the public comment period on September 29, 2016. This plainly is not enough time for the Department to review let alone meaningfully consider and respond to all comments

 ¹²² Duke Energy Florida's Petition for Approval of Environmental Cost Recovery True-Up and 2017 Environmental Cost Recovery Clause Factors, Docket No. 160007-EI (August 31, 2016). Recent PSC filing – 07181-16
 ¹²³ Draft Permit at 14.

in writing.¹²⁴ As we explained in our February 29, 2016, letter, due to the importance of the water impacts and protections at issue in this permit renewal, DEP should go above and beyond its routine public participation practices, not truncate them.

CONCLUSION

For all the foregoing reasons, we respectfully ask that, in issuing Crystal River Unit 4 and 5's renewed NPDES permit, DEP:

- 1. Set a technology-based zero discharge standard for bottom ash wastewater and require compliance with the standard no later than November 1, 2018;
- 2. Set a technology-based zero discharge standard for FGMC wastewater and require compliance with the standard no later than November 1, 2018;
- 3. Set technology-based limits on arsenic, mercury, selenium and nitrate/nitrite in FGD wastewater and require compliance with the standard no later than December 2018;
- 4. Establish technology-based BPT effluent limits and daily monitoring requirements for FGD and FGMC wastewater flows, effective immediately;
- 5. Apply BPT limits to discharges of CRL from the Ash Landfill to the runoff collection system and to Crystal Bay, and conduct a reasonable potential analysis to determine whether WQBELs are needed for greater protection;
- 6. Require clean up and corrective action, as mandated by the CCR Rule, to swiftly address ongoing groundwater contamination from the unlined Ash Landfill and to take all measures necessary to protect against further leaching of toxic metals into ground and surface waters including, retrofitting or closing the unit; and
- 7. Require compliance with the CCR Rule's prohibition on siting CCR units in unstable areas, so as to further protect ground and surface waters.

Timing is critical: To meet the deadlines for implementing ground and surface water protections—which also protect the public use of those waters—DEF will have to undertake changes to coal operations at CREC Units 4 and 5. DEF must not delay, or be excused by DEP through extensions or deferrals to future permit renewal cycles, for which there is no justification let alone a well-documented one in this permitting record.

Thank you for your consideration.

Sincerely,

¹²⁴ Draft Permit at 15.

<u>/s/ Elizabeth Tedsen Winkelman</u> Elizabeth Tedsen Winkelman Law Office of Elizabeth T. Winkelman Phone: 530-524-2702 E-mail: etedsenlaw@gmail.com *Outside Counsel for Sierra Club*

/s/ Diana Csank Sierra Club 50 F Street, Eighth Floor Washington, DC 20001 Phone: 202-548-4596 E-mail: diana.csank@sierraclub.org

/s/ Justin Bloom Executive Director Suncoast Waterkeeper Phone: (941)275-2922 Email: bloomesq1@gmail.com http://suncoastwaterkeeper.org https://www.facebook.com/Suncoastkeeper

/s/ Amelia Shenstone Campaigns Director Southern Alliance for Clean Energy 250 Arizona Ave., NE Atlanta, GA 30307 Phone: 404.373.5832 x3 Email: Amelia@cleanenergy.org

Cc:

EPA Region 4 (r4npdespermits@epa.gov) Karrie Jo-Shell, Power Plant NPDES Permits, EPA Region 4 (shell.karrie-Jo@epamail.epa.gov) Chairman, Board of Citrus County Commissioners (ronald.kitchen@citrusbocc.com) FWC, Conservation Planning Services (fwcconservationplanningservices@myfwc.com) Jim Valade, U.S. Fish and Wildlife Service (jim_valade@fws.gov) Florida Department of Economic Opportunity, State Land Planning Agency (DCPPermits@deo.myflorida.com) Florida Department of State, Bureau of Historic Preservation (compliancepermits@dos.state.fl.us) U.S. Army Corps of Engineers (james.j.mcadams@usace.army.mil) Cindy Zhang-Torres, DEP Tampa (cindyzhang.torres@dep.state.fl.us) Ramandeep Kaur, DEP Tampa (ramandeep.kaur@dep.state.fl.us) Ilia Balcom, DEF (Ilia.Balcom@duke-energy.com) Brian Powers, Duke Energy (brian.powers@duke-energy.com)

EXHIBIT 1

Preparing for the U.S. Environmental Protection Agency's Coal Combustion Residuals Rule: Technical Assessment of Hydrogeologic Conditions and Groundwater Contamination at the Crystal River Energy Complex

August 28, 2016

By Mark Stewart, PhD, PG

1. EXECUTIVE SUMMARY

The Crystal River Energy Complex ("CREC") is located on unstable karst terrain, and the primary facility used for the storage and disposal of coal combustion residuals ("CCR") at CREC, the Ash Landfill, exhibits increasing contamination from toxic heavy metals associated with CCR waste. CCR disposal and storage at CREC puts local water resources at risk and fails to meet the new safety standards by the U.S. Environmental Protection Agency ("EPA") in December 2014 ("the CCR Rule") for several reasons:

- CREC is located in one of the country's most unstable areas, in karst terrain, and is under the influence of multiple sinkholes, including 24 reported sinkholes within 5 miles of CREC.
- The risk of limestone dissolution and sudden collapse beneath CREC's Ash Landfill is increased by many factors, including (a) having no impermeable liner; (b) having no cover to exclude precipitation from the exposed ash waste; and (c) CCR accumulating at the Ash Landfill increasing the static load on the underlying, unstable soils and rock.
- To assure the safety of CCR storage and disposal in such unstable areas, EPA's CCR Rule requires the detection and interception of (a) all of the possible conduits that allow piping of groundwater into underlying karst aquifers; (b) all of the possible shallow caves that could cause a sudden foundation collapse; and (c) all of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities into karst aquifers. Consulting reports state that at CREC, "most [groundwater] flow is through solution cavities and conduits." These safety standards were not incorporated into the design of the Ash Landfill when it was built, and it is now nearly impossible to do so.
- The Ash Landfill was not built to structurally withstand the influence of sinkholes. It lacks the
 structural reinforcement that would be necessary, but may nevertheless be insufficient, to
 prevent a sudden foundation collapse. The Ash Landfill cannot be retrofitted now to be safe.
 Attempting a retrofit could trigger a sinkhole collapse that could rapidly spread CCR
 contamination in the underlying karst aquifers.
- To protect public waters, the CCR Rule requires (a) a distance of at least 5 feet between the base
 of CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that
 eliminate any hydraulic connection between CCR storage and disposal facilities and the aquifer—
 CREC Ash Landfill does not meet either standard. In fact, the available monitoring data are
 indicative of an ongoing hydraulic connection that allows CCR constituents, including arsenic and
 other heavy metals associated with CCR leachate, to reach the underlying karst aquifers.
- Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination since 2012 with toxic constituents associated with CCR, such as

arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has contaminated the Surficial and Floridan Aquifer at the site.

• Groundwater beneath CREC Ash Landfill, FGD Blowdown Ponds, and Percolation Ponds flows towards the seawater discharge canal, tidal wetlands, and Crystal Bay.

For these reasons, discussed in detail in the full report, the Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

2. INTRODUCTION

This is an assessment of coal combustion residuals ("CCR") storage and disposal at the Crystal River Energy Complex ("CREC"). This assessment evaluates hydrogeologic conditions at the Ash Landfill, FGD Blowdown Ponds, Gypsum Storage Pad, and Percolation Ponds, existing groundwater contamination at CREC, and compliance with the U.S. Environmental Protection Agency's ("EPA") new rule on the disposal of CCR from electric utilities ("CCR Rule," U.S. EPA 2015). More specifically, this assessment considers whether CREC's CCR facilities satisfy the safety standards in the CCR Rule for CCR disposal in karst terrain and away from the uppermost aquifer and for preventing groundwater contamination.

The karst-specific safety factors under CCR Rule can be summarized as follows:

- 1. The historical record of local sinkhole development;
- 2. The presence of a local hydraulic gradient that points downward at shallow depths;
- 3. The presence of subsurface conduits that allow piping of groundwater into the karst aquifer, or shallow conduits or caves that could cause sudden collapse of the structure's foundation; and
- The use of engineering solutions to "prevent the kind of foundation collapse and settlement that could lead to sudden release to the environment of CCR with its toxic constituents and associated leachate." (U.S. EPA 2015).

As discussed below, these factors support the conclusion that CREC Ash Landfill cannot continue to safely receive CCR, nor can it meet the requirements of the CCR Rule.

Additionally, the CCR Rule requires (a) a distance of at least 5 feet between the base of certain CCR storage and disposal facilities and the uppermost aquifer, or (b) other measures that eliminate any hydraulic connection between the facilities and the aquifer. As discussed below, the Ash Landfill does not meet either of these standards.

Water quality samples from wells downgradient from the Ash Landfill show consistent and increasing contamination from common CCR constituents, such as arsenic, boron, molybdenum, manganese, selenium, sulfate, and thallium, indicating that the Ash Landfill has already contaminated the Surficial and Floridan Aquifer at the site.

The Ash Landfill cannot meet the safety standards in the CCR Rule. Additionally, as the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site decontaminated. The only way to prevent such continued releases from the Ash Landfill is to remove the CCR that has accumulated and decontaminate the site.

3. ASSESSMENT

A. CREC is in one of the country's most unstable areas, under the influence of multiple sinkholes

CREC is located in Citrus County, an active karst area under the influence of sinkholes (FGS 1985). The sandy sediment cover over the limestone in coastal Citrus County is thin, and sinkholes that form tend to be smaller, i.e., less than 10 feet ("ft") in diameter, and not as deep as in areas with thicker, more cohesive sediments covering the limestone. However, the near-surface limestone is deeply incised with solution channels and conduits that can cause small sinkholes to form as surficial sands move into the subsurface voids (Dames and Moore 1994).

a. Hydrogeology of coastal West Florida: Karst terrain, solution conduits, and sinkholes

Coastal Citrus County is a region that is underlain by a thick sequence of carbonate rocks, commonly called "limestone" (Miller 1986). These rocks can be dissolved by the chemical action of acidic groundwaters. This creates voids in the rock and a distinctive geologic terrain called karst.¹ Karst terrains are characterized by solution features such as caves and collapse features caused by surface materials falling into voids created by the solution of the underlying rocks. A vertical collapse or solution feature created by karst activity is called a sinkhole (Tihansky 2013).

Small sinkholes are common in western Citrus County (FGS 2016; Tihansky 2013). These voids or depressions at the surface are caused by the movement of unconsolidated surficial materials into preexisting voids in the underlying limestone. Sinkholes can form rapidly by collapse or slowly by movement of surficial materials into underlying voids in the carbonate rock. Most sinkholes in coastal Citrus County are cover subsidence sinkholes. These sinkholes form when loose surficial sands migrate downward into solution cavities in the limestone. Cover subsidence sinkholes can form slowly, or abruptly, especially after heavy rainfall (Tihansky 2013).

¹ Geologists generally use the term "terrane" to refer to three-dimensional areas including the surface and subsurface, and "terrain" to refer to the surface configuration or topography only. This assessment uses "terrain" to refer to both surface and subsurface areas unless otherwise noted.

Granular sediments spall into secondary openings in the underlying carbonate rocks.

ments settles into the vacated spaces (a process termed "piping").

tinue, forming a noticable depression in the land surface.

A column of overlying sedi- Dissolution and infilling con- The slow downward erosion eventually forms small surface depressions I inch to several feet in depth and diameter.



Figure 1. Cover subsidence sinkhole schematic (Tihansky 2013)

Paleosinks or paleo-sinkholes are also common in West Central Florida (Tihansky 2013). These are cover subsidence sinkholes that have been filled by sediments or water and do not have recognizable depressions at the surface. Such sediment-filled sinkholes can create a vertical column of permeable materials that allow contaminants introduced at the water table to reach the Floridan Aquifer. In addition to sinkholes, the limestone underlying CREC contains many solution enlarged fractures that form preferred conduits for groundwater flow and allow for downward movement of surficial sands into the underlying limestone (Dames and Moore 1994).

Groundwater, particularly groundwater in the Surficial and Floridan Aquifers,² supplies the region's public drinking water. The Floridan Aquifer is one of the largest and most productive sources of fresh groundwater in the world (Miller 1986). It is comprised of the carbonate rocks of Eocene to Miocene age in West Central Florida. In coastal western Citrus County, the Floridan Aquifer is unconfined and water table elevations represent the potentiometric surface of the Floridan Aquifer. This area is a recharge zone for the shallow Floridan Aquifer, which is at or within a few feet of land surface at CREC. More specifically, shallow groundwater flows downward from the water table and the shallow sands of the Surficial Aquifer into the Floridan Aquifer. Near CREC, the deeper and intermediate portions of the Floridan Aquifer are discharge zones, and groundwater has a component of flow toward the surface.

b. Hydrogeology of CREC site

The Florida Geological Survey ("FGS") sinkhole database (FGS 2016) documents 24 reported sinkholes within 5 miles of CREC site. As the FGS sinkhole data are self-reported, the 24 reported sinkholes are the minimum number of sinkholes that have occurred in recent years near CREC site. The FGS database is biased toward residential and commercial areas where sinkholes are more likely to be reported than in rural areas and industrial sites. Most of the reported sinkholes near CREC site are reported along the U.S. Highway 19 corridor east of CREC site and associated residential areas. The reported sinkholes are smaller than sinkholes that occur in central Florida, generally less than 10 ft in

² The Surficial and Floridan Aquifers are U.S. EPA designated Underground Sources of Drinking Water, and Florida Department of Environmental Protection ("DEP") designated Type G-II (Surficial) and G-I (Floridan) groundwaters.

diameter and up to 10 ft in depth. Using the 24 sinkholes as a representative data set, 95% (two standard deviations) of reported sinkholes within 5 miles of CREC have diameters less than 7 ft. They are indicative of the extensive karst solution cavities that are present in the shallow subsurface in western Citrus County.

Dames and Moore (1994) describe the geology and hydrogeology of CREC site. The following discussion is a summary of the geology and hydrogeology of CREC site from that report.

Dames and Moore report that the Upper Floridan Aquifer at CREC site contains abundant "solution enlarged fractures," "long linear depressions" in the limestone surface, and "underground channels and caverns." They also report that during removal of coal ash from the area of the former CREC south ash pond, "local superficial channels/sinkholes concealed by ash deposits had caused a continuous series of incidents and delayed removal/transportation activities." The report also states that "most flow is through the solution channels and cavities" and that the upper zone from the surface to a depth of about 30 feet contains many large interconnected solution cavities and channels that are highly permeable.

The surficial deposits at CREC consist of predominantly sandy, unconsolidated materials with some silt and clay. There is no distinct Surficial Aquifer at the site, and the Floridan Aquifer is within a few feet of the land surface. Water reaching the water table from the surface is effectively recharging the upper part of the Floridan Aquifer. The permeable surficial sediments are in direct hydraulic connection with the limestones of the Upper Floridan Aquifer. As a result of the lack of extensive low permeability surficial materials, the Floridan Aquifer at CREC site is an unconfined aquifer in direct hydraulic connection with the water table. Soils at the site typically have seasonal water tables within 1-2 ft of the land surface and are described as poorly drained. The undisturbed soils at CREC are subject to frequent and prolonged flooding.

The near-surface Floridan Aquifer units present at the site are the limestones of the Ocala Group, specifically the lower member of the Ocala Group, the Inglis Formation. The Inglis Formation is an Eocene limestone with extensive solution features. The Avon Park Formation underlies the Inglis Formation. The Avon Park Formation consists of limestones and dolostones and forms the bottom of the Upper Floridan Aquifer (Miller 1986). The permeability of the Avon Park decreases with depth. This results in enhancement of horizontal ground water flow in the Inglis Formation limestones. Dames and Moore (1994) report that most groundwater flow at the site is through "solution cavities and channels." In test borings that encountered voids, about 10% of the total aquifer volume is void space, generally within 50 ft of land surface. A zone in the Inglis Formation from land surface to a depth of about 30 ft consists of "many large solution cavities and channels that are highly permeable." A lower high permeable zone occurs between depths of about 40 to 60 ft at the contact between the Inglis and Avon Park Formations. Aquifer performance data suggest that the transmissivity of the Upper Floridan Aquifer at the site is about 2E05 ft²/day, a very high value.

In a study to support installation of CREC Units 4 and 5 at CREC (ESE 1982), Dames and Moore (1994) report that test borings could be divided into "void" borings that encountered voids during

drilling, and "non-void" borings that encountered solid limestone. The eight void wells responded faster to recharge events and tides and were assumed to connect with solution cavities and channels. The water levels for the void group wells were found to "form a trough running northeast to southwest under the ash disposal site...this trough roughly coincides with the known subsurface cavities in this area and likely reflects a fracture zone of high permeability." The general groundwater flow direction under the Ash Landfill indicated by the void and non-void wells is northeast to southwest, toward CREC intake and discharge canals and wetlands to west of CREC. Groundwater that flows under the Ash Landfill through the "trough" delineated by Dames and Moore (1994) flows toward the west-southwest and discharges into the seawater discharge canal, and ultimately into Crystal Bay.

The water table "trough" under the Ash Landfill reported by Dames and Moore (1994) includes monitor wells MWI-2R2, TWI-5, and TWI-3 (Figures 2 and 3). These three monitor wells are located on the west side of the Ash Landfill. As described further below, groundwater monitoring reports (DEP 2015) indicate that these three wells have been contaminated with arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron, all of which are contaminants associated with CCR leachate. This indicates that the Ash Landfill is in direct hydraulic connection with a highly permeable fracture zone in the Upper Floridan Aquifer, and that contaminants associated with CCR wastes have entered the Upper Floridan Aquifer.



Figure 2. Water table elevations under the Ash Landfill (Dames and Moore 1994)



Figure 3. Groundwater Monitoring Network at CREC (Geosyntec 2013)

B. CREC Ash Landfill cannot meet the CCR Rule's safety standards for unstable areas

Historical records of sinkhole activity in the region and reports prepared for CREC site clearly indicate that the site is within an active karst zone, with numerous, unlocated channels and voids. Consulting reports (Dames and Moore 1984; ESE 1982) state that at CREC "most [groundwater] flow is through solution cavities and conduits" and these reports document that the site contains numerous solution enlarged channels, voids, and caves, with one documented high permeability conduit located directly under the Ash Landfill (Dames and Moore 1994). These channels, conduits, limestone surface depressions, and voids create a sinkhole hazard for the Ash Landfill.

The Floridan Aquifer is at or near land surface at CREC site (Dames and Moore 1994) and any size sinkhole is likely to allow movement of unconsolidated materials under the CCR landfill into the voids, depressions, and caverns under the landfill will, and likely has (ESE 1982), allowed CCR materials to come into direct contact with the limestones and groundwater of the Upper Floridan Aquifer. The Ash Landfill does not have structural reinforcements or a liner³ to prevent vertical movement of CCR materials into the Upper Floridan Aquifer, as occurred at the site of the former CREC south ash pond (ESE 1982).

³ Only 5.5 acres of the 62-acre Ash Landfill are lined.

To ensure the safety of CCR storage and disposal in unstable karst areas, the CCR Rule requires the detection and interception of (a) *all* of the possible conduits that allow piping of groundwater into the underlying karst aquifers; (b) *all* of the possible shallow caves that could cause a sudden foundation collapse; and (c) *all* of the possible pathways for CCR constituents to be released from CCR storage and disposal facilities, such as the Ash Landfill, into the karst aquifers (U.S. EPA 2015).

These safety standards were not incorporated into the design of the Ash Landfill when it was built. Detection and interception of *all* possible conduits, depressions, voids, and shallow caves in a complex karst terrain such as CREC site is extremely difficult technically, if not practically and economically infeasible. With any currently known sinkhole remediation technology, the Ash Landfill cannot be "upgraded" to meet the CCR Rule requirements for facilities in karst terrains as it would be nearly impossible to determine that all conduits, voids, and caves had been detected and intercepted. As the Ash Landfill does not meet the CCR Rule's safety standards and instructions for engineering practices in karst areas, the CCR materials currently onsite should be removed and the groundwater and soils decontaminated.

In addition to the Ash Landfill, CREC site contains a Gypsum Storage Pad, which receives gypsum solids before disposal in the Ash Landfill or transport offsite, and FGD Blowdown Ponds and Percolation Ponds on the west side of the site, adjacent to the seawater discharge canal, that receive waste and wastewater from coal operations. The FGD Blowdown Ponds are lined with synthetic impermeable liners. However, the FGD Blowdown Ponds, Percolation Ponds, and Gypsum Storage Pad are in the same unstable karst environment as the Ash Landfill. There is a potential for failure of the FGD Blowdown Pond liner system or piping as result of sinkhole activity. If a sinkhole punctured the liner or caused a FGD pipe to leak, the FGD wastes would be introduced directly into the Upper Floridan Aquifer, discharging to the seawater discharge canal, tidal wetlands, and ultimately Crystal Bay. The liner system would need to be able to span sinkholes 10 ft in diameter or greater without failing to avoid contaminating the Upper Floridan Aquifer with FGD wastes. The Percolation Ponds are unlined and are in direct communication with the Upper Floridan Aquifer. The Percolation Ponds recharge the shallow groundwater aquifer and discharge into the seawater discharge canal, tidal wetlands, and Crystal Bay (Figures 2 and 3).

C. The Upper Floridan Aquifer exhibits contamination from CCR Leachate at CREC

Contaminants such as sulfate, arsenic, selenium, thallium, boron, molybdenum, and manganese are common constituents of CCR leachate (EPRI 2004). The presence of several of these constituents, at any detectable level above background values, in groundwater downgradient from a CCR storage and disposal unit is overwhelming evidence that contaminants that have leached from the CCR materials have reached the water table and the aquifer. Groundwater sampling results from September 2012 for monitoring well MZ-3, which is in an upgradient, undisturbed area approximately one mile east of CREC facility, indicate that background arsenic concentrations in the shallow, intermediate, and deep portions of the aquifer are 2.1, 6.3, and <2.0 micrograms/liter, respectively (Geosyntec 2013). Arsenic levels in groundwater >10.0 micrograms/liter are indications of contamination of the aquifer system by CCR.

Dames and Moore (1994) state that the "void wells" near the Ash Landfill define a "trough" in the water table surface underneath the landfill (Figure 2). They attribute this water table trough to a "fracture zone of high permeability." Three monitor wells on the west side of the Ash Landfill are located in or near this high permeability fracture zone: wells MWI-2R2, TWI-5, and TWI-3 (Figure 3).

Water samples from these three wells have regularly exceeded federal and state regulatory levels for arsenic, sulfate, thallium, selenium, molybdenum, manganese, and boron since 2012. For arsenic, boron, manganese, and molybdenum levels of these contaminants in groundwater in this fracture zone have trended upward from 2012 to 2015 (Figures 4, 5, 6, and 7). Water quality data obtained in January 2016, continue to show levels of contaminants in excess of groundwater standards in wells downgradient of the Ash Landfill in wells MWI-2R2, TWI-1R, TWI-3, and TWI-5 (DEP 2016).

These supporting lines of evidence, the definition of the water table trough, the presence of high permeability conduits at the site, and the presence of common CCR leachate constituents at increasing concentrations in wells downgradient from the Ash Landfill are overwhelming evidence that the landfill has contaminated local groundwater with toxic materials associated with CCR leachate. As the purpose of the standards enumerated under the CCR Rule is to prevent groundwater contamination from CCR facilities, the presence of these contaminants at the existing site is evidence that the existing Ash Landfill does not meet the conditions specified in the rule.

Geosyntec (2013) has prepared a report that maintains that the arsenic found in groundwater downgradient from the Ash Landfill is the result of complex geochemical conditions and a natural source of arsenic. They note that arsenic was detected in borings at a proposed coal ash storage site east, and upgradient, of the current Ash Landfill, suggesting a natural source of arsenic. However, the concentrations of arsenic detected downgradient of the Ash Landfill are up to five times as high as the concentrations detected upgradient. In addition, the associated CCR contaminants sulfate, selenium, thallium, boron, molybdenum, and manganese have been detected in wells downgradient of the Ash Landfill. The Geosyntec report does not explain the presence of these CCR associated contaminants.

To prevent such contamination, the CCR Rule prescribes (a) a distance of at least 5 feet between the base of facilities containing CCR and the uppermost aquifer, or (b) other measures that eliminate the hydraulic connection between the base and the uppermost aquifer—safety standards that the Ash Landfill does not meet. According to public records, the base of the Ash Landfill has an elevation of 4 to 8 feet above sea level, while the water table near the Ash Landfill has reported elevations greater than 3 feet (Geosyntec 2013). This indicates that the base of the Ash Landfill is within 5 feet of the water table in the Surficial/Floridan Aquifer. The Ash Landfill is unlined, meaning that the CCR materials are in direct hydraulic connection with the Floridan Aquifer. Furthermore, natural soils at CREC site are poorly drained and flood seasonally (Dames and Moore 1994), indicating that the water table seasonally approaches the land surface. As the CCR Rule requires corrective action to prevent further releases of CCR constituents into the environment, the CCR that have accumulated in the Ash Landfill should be removed and the site should be decontaminated.



Figure 4. Arsenic levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)



Figure 5. Boron levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)



Figure 6. Manganese levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)



Figure 7. Molybdenum levels in groundwater samples from wells at CREC site, October 2012 to July 2015 (DEP 2015)
4. SUMMARY

CREC Ash Landfill does not meet the safety criteria for CCR landfills and impoundments enumerated in the EPA's CCR Rule. The facility is located in a documented unstable, karst area, putting local water resources at risk. It would be technically challenging, if not impossible to upgrade the Ash Landfill to meet the CCR Rule standards for active facilities in karst areas. In addition, there is overwhelming evidence that the Ash Landfill has contaminated local ground water with arsenic, selenium, molybdenum, manganese, boron, and thallium. The source of these contaminants is the Ash Landfill as documented by the presence of these contaminants in water samples from downgradient wells. The Ash Landfill is uncovered and open to infiltration of rainwater, the facility is unlined, and it is in direct hydraulic connection with the Upper Floridan Aquifer. The remedy to prevent further contamination of the aquifer and of Crystal Bay, is to remove the CCR materials currently on site and to decontaminate the Floridan Aquifer and local soils.

5. AUTHOR'S EXPERTISE AND QUALIFICATIONS

The author of this technical assessment, Dr. Mark Stewart, PhD, PG, is a Professor Emeritus at the University of South Florida School of Geosciences. Dr. Stewart is a registered Professional Geologist in the State of Florida. He has an extensive publication record and expertise in the hydrogeology of Florida, water resources management, karst hydrology, applied geophysics, and the geology of sinkholes. He has been qualified in hearings of the Division of Administrative Hearings and in State and Federal courts as an expert in hydrogeology, water resources management, karst hydrology, the geology of sinkholes, hydrologic modeling, and environmental geophysics. Dr. Stewart has an undergraduate degree in geological sciences from Cornell University, and graduate degrees in geology and water resources management from the University of Wisconsin-Madison.

The primary materials reviewed and used in the preparation of this assessment were Florida Department of Environmental Protection ("DEP") regulatory files, which include groundwater monitoring reports, reports on the geology and hydrogeology of CREC site, and reports on the construction and operation of waste material facilities and disposal of generated wastes, all of which were prepared by Duke/Progress Energy/FPC and their consultants and submitted to the DEP. Additional materials referenced for this report include: publications, data, and maps from the U.S. Geological Survey and Florida Geological Survey; peer-reviewed journal articles; and publically-available documents related to coal and coal combustion residuals, hydrogeology, sinkholes, and karst hydrology.

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EXHIBIT 2

Technical Assessment of Converting a Zero Discharge Standard for Bottom Ash Wastewater at the Crystal River Energy Complex:

Expert Report by Dr. Ranajit (Ron) Sahu

Ranget Salu

September 26, 2016

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1. EXECUTIVE SUMMARY

This is an assessment of Duke Energy Florida's ("DEF") plans for achieving compliance with the U.S. Environmental Protection Agency's ("EPA") revised effluent limitations guidelines ("ELGs") for bottom ash wastewater generated at DEF's Crystal River Energy Generating Complex ("CREC") Units 4 and 5. Specifically, this assessment evaluates DEF's contention that February 1, 2020, should be the deadline for these units under the ELGs.

DEF's 44-month schedule to achieve compliance with the bottom ash BAT standard is simply unsupported. CREC can achieve a zero discharge standard for bottom ash wastewater within 27 to 30 months, roughly August to November 2018.

Construction time for bottom ash retrofits at Units 4 and 5 are anticipated to take, with a built in contingency, only 18 months. Other, related, tasks for achieving compliance should take significantly less time than DEF proposes, particularly as DEF began planning for and evaluating strategies to comply with the revised ELGs as far back as 2012. Beginning in 2014, Duke Energy began publicly reporting projected compliance costs, suggesting that conceptual or detailed engineering evaluations and studies were undertaken and that Duke Energy's Board has been aware of these changes and costs for some time.

DEF does not need until February 1, 2020, to achieve compliance with a zero discharge standard for bottom ash wastewater at CREC Units 4 and 5. Rather, compliance can be achieved by November 2018 if not sooner. The Florida Department of Environmental Protection ("DEP") should carefully review the unsupported schedule provided by DEF and require that Units 4 and 5 comply with a zero discharge bottom ash standard by no later than November 2018.

2. INTRODUCTION

This is an assessment of Duke Energy Florida's ("DEF") plans for achieving compliance with the U.S. Environmental Protection Agency's ("EPA") revised effluent limitations guidelines ("ELGs") for bottom ash transport water¹ or "wastewater" generated at DEF's Crystal River Energy Generating Complex ("CREC") Units 4 and 5. Specifically, this assessment evaluates DEF's contention that February 1, 2020, should be the deadline for these units' under the ELGs.

3. BOTTOM ASH HANDLING AND WASTEWATER AT CREC UNITS 4 AND 5

¹ 40 C.F.R. § 423.11(f) (defining the term "bottom ash" as "the ash, including boiler slag, which settles in the furnace or is dislodged from furnace walls. Economizer ash is included in this definition when it is collected with bottom ash); § 423.11(p) (defining the term "transport water" as "any wastewater that is used to convey fly ash, bottom ash, or economizer ash from the ash collection or storage equipment, or boiler, and has direct contact with the ash. Transport water does not include low volume, short duration discharges of wastewater from minor leaks (e.g., leaks from valve packing, pipe flanges, or piping) or minor maintenance events (e.g., replacement of valves or pipe sections)."

CREC is operated by DEF and is located adjacent to Crystal Bay, part of the Gulf of Mexico, in Citrus County, Florida. Units 1 (built in 1966, rated at 395 MW), 2 (built in 1969, rated at 520 MW), 4 (built in 1982, rated at 769 MW), and 5 (built in 1984, rated at 767 MW) are Duke Energy's only coal-fired units in Florida.² DEF applied to renew the NPDES Permit No. FL0036366 for Units 4 and 5 in January 2016.³

As described by DEF, Units 4 and 5 produce bottom ash wastewater that discharges from dewatering bins to an internal canal and then to Crystal Bay via a discharge canal:

The bottom ash handling system collects and removes bottom ash from Crystal River North Unit 4 & 5. Bottom ash collected in ash hoppers beneath the steam generator is periodically removed with ash sluice water to a transfer tank. From the transfer tank, an ash slurry pump transports slurry to a selected dewatering bin where bottom ash is separated from the transport water. When dewatered, bottom ash is either directly sent for beneficial reuse or deposited in an ash storage area for later beneficial reuse. All transport water from the dewatering bin is sent to a surge tank where it is pumped back to the ash hoppers to transport more bottom ash. Several process streams also feed into the bottom ash transport water system. While they provide needed make-up water, these sources may also, at times, cause the surge tank to overflow. The overflow runs into the coal area stormwater runoff ditch which discharges infrequently through NPDES internal outfall I-CHO.4

DEF further describes:

The facility currently utilizes a wet-sluicing system for bottom ash, in which most of the bottom ash transport water is reused after exiting the dewatering basins. However, due to water balance issues at the facility, an overflow structure is used to discharge excess water from the dewatering basins into the runoff collection system, and then through Internal Outfall I-CHO to eventually Internal Outfall I-0CO, Outfall D-001 and waters of the State.⁵

Additional details are provided in the NPDES permit renewal application and other documents in the permitting record.⁶

² See Coal-Fired Plants, Duke Energy, <u>https://www.duke-energy.com/power-plants/coal-fired.asp (last visited Sep. 26, 2016).</u>

³ Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016.

⁴ Duke Energy Florida, Response to Request for Additional Information, Attachment 1 at 1, May 20, 2016.

⁵ Draft Permit at 12.

⁶ See e.g., DEF's Coal Combustion Product (CCP)/Solid Waste Materials Management Plan, Revision 6, December 2013.

4. THE ELGS

After many years of work,⁷ EPA finalized the ELGs in November 2015.⁸ The ELGs revise and strengthen technology-based effluent limitations guidelines and standards for wastewater discharges from steam electric power plants, including coal-fired units such as CREC Units 4 and 5.

The final ELGs set federal limits on the discharge toxic metals and other harmful pollutants from wastewater at steam electric power plants. The ELGs are based on technology improvements in the steam electric power industry over the last three decades and establish new requirements for wastewater streams from the following processes and byproducts associated with flue gas desulfurization, fly ash, bottom ash, flue gas mercury control, and gasification of fuels such as coal and petroleum coke.

The ELGs require a zero discharge best available technology ("BAT") standard for bottom ash wastewater to be achieved by November 1, 2018, or "as soon as possible."⁹ The phrase "as soon as possible" means November 1, 2018, unless permitting authorities, such as the Florida Department of Environmental Protection ("DEP"), establish a later date based on a welldocumented justification.¹⁰

5. CONSULTATION WITH VENDORS AND INDUSTRY REGARDING BOTTOM ASH CONVERSIONS

A. Vendor Experience and Discussions During ELG Rulemaking

As EPA has stated, "to gather information on handling fly ash and bottom ash, EPA ... contacted several ash handling and ash storage vendors. The vendors provided the following types of information for EPA's analyses:

- Type of fly ash and bottom ash handling systems available for reducing or eliminating ash transport water;
- Equipment, modifications, and demolition required to convert wet-sluicing fly ash and bottom ash handling systems to dry ash handling or closed-loop recycle systems;
- Equipment that can be reused as part of the conversion from wet to dry handling or in a closed-loop recycle system;

⁷ As EPA noted in the preamble to the final ELG Rule, "....EPA initiated a steam electric ELG rulemaking following a detailed study in 2009. EPA published the proposed rule on June 7, 2013, and took public comments until September 20, 2013." 80 Fed. Reg. 67,844.

⁸ The Final ELG Rule was published in the Federal Register on November 3, 2015. 80 Fed. Reg. 67,838.

⁹ See 40 C.F.R. § 423.11(t) (defining the phrase "as soon as possible" to mean Nov. 1, 2018, unless a later date is specifically justified); § 423.13(k)(1) (requiring compliance with bottom ash wastewater standards by Nov. 1, 2018 unless a later date up to Dec. 31, 2023 is specifically justified).

^{10 40} C.F.R. § 423.11(t) (emphasis added).

- Outage time required for the different types of ash handling systems;
- Maintenance required for each type of system;
- Operating data for each type of system;
- Purchased equipment, other direct, and indirect capital costs for fly ash and bottom ash conversions;
- Specifications for the types of ash storage available (*e.g.*, steel silos or concrete silos) for the different types of handling systems;
- Equipment and installation capital costs associated with the storage of fly ash and bottom ash; and
- Operation and maintenance costs for fly ash and bottom ash handling systems."¹¹

The vendor community has been well aware of the rule requirements and participated fully in the rulemaking. There are numerous well-qualified U.S. vendors (and foreign vendors that are active in the U.S. market) that are capable of providing equipment and services for ash handling and conversion of bottom ash transport water at coal-fired units such as Units 4 and 5. Major vendors include United Conveyer Corporation ("UCC"),¹² Clyde Bergemann,¹³ and Magaldi.¹⁴ Others such as GE, Veolia, Nalco, Aquatech, Heartland, LB Industrial Systems, and many others also have potential capabilities and solutions for specific aspects of ash handling. The ELGs docket shows that EPA consulted expensively with at least UCC and Clyde Bergemann with respect to bottom ash transport water and handling during rule development.¹⁵.

That the vendor community is robust is not surprising given that the US coal-fired power plant fleet is over 800 units strong, with each one generating copious amounts of bottom ash that must be handled and managed. Further, as the ELGs rulemaking record shows, a significant portion of the U.S. coal fleet already meets the ELGs BAT standard for bottom ash wastewater and are dry systems. These vendors already have many technology solutions and offerings for achieving

¹¹ Technical Development Document for the Effluent Limitation Guidelines and Standards for the Steam Electric Power Generating Point Source Category, U.S. Environmental Protection Agency, EPA-821-R-15-007 at p. 3-21 and 3-22 (Sep. 2015).

¹² UCC offers various hydraulic, mechanical, pneumatic, and vibratory systems for dry bottom ash handling.

See Bottom Ash, United Conveyor Corporation, <u>http://unitedconveyor.com/bottom_ash/ (last visited Sep. 26, 2016).</u>

¹³ Clyde Bergemann offers a trademarked "DRYCON" system for dry bottom ash handling.

See DRYCON, Clyde Bergemann Power Group, <u>http://www.cbpg.com/en/products-solutions-materials-handling-bottom-ash/drycon%E2%84%A2 (last visited Sep. 26, 2016).</u>

¹⁴ Magaldi offers a dry ash handling system called MAC. A variant of this system appears to have been installed in either CREC Unit 1 or 2 or both.

See Magaldi Solutions for Ash Handling, Magaldi, http://www.magaldi.com/en/magaldi_solutions_for/Ash-Handling-Mac_9_11.php#tab_fototab_(last visited Sep. 26, 2016).

¹⁵ See, for example, EPA-HQ-OW-2009-0819-0580 (pertaining to EPA and its contractor's discussions with UCC) (available at https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-0580) and EPA-HQ-OW-2009-0819-6232 (pertaining EPA and its contractor's discussions with Clyde to Bergemann) (available at https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-6232).

a zero discharge bottom ash standard. As the preamble to the ELG Rule states:

...technologies for control of bottom ash transport water are demonstrably available. Based on survey data, more than 80 percent of coal-fired generating units built in the last 20 years have installed dry bottom ash handling systems. In addition, EPA found that more than half of the entities that would be subject to BAT requirements for bottom ash transport water are already employing zero discharge technologies (dry handling or closedloop wet ash handling) or planning to do so in the near future.¹⁶

Thus, DEF has a good selection of experienced vendors to select from to achieve compliance with the bottom ash ELGs. As discussed below, the record also shows that DEF and previous CREC owner Progress Energy Florida ("PEF") appear to have actively consulted with at least one vendor, UCC, with regards to bottom ash dry conversion systems, as far back as 2012.

B. Vendor Discussions Pertaining to DEF and CREC in the Rulemaking Docket

The ELG rulemaking docket indicates that DEF already consulted vendors regarding the conversion to bottom ash dry conversion systems. Specifically, the docket shows that DEF has a long-standing relationship with one of the vendors, Magaldi,¹⁷ and has been discussions with another vendor DRYCON[™].¹⁸ In addition, the docket shows DEF has experience with other vendors through its pursuit of dry systems at its other plants/units. Moreover, DEF and its predecessor, Progress Energy Florida (PEF), have been engaged for years in developing a compliance strategy for bottom ash transport water for Units 4 and 5. As EPA notes in a memorandum provided by its contractor ERG in May 2012:

UCC noted the wet to dry conversions in the recent past or in process:

. . .

- <u>Duke Energy's</u> Gibson plant is in the process of converting their wet sluicing system to a dry fly ash handling system;

. . .

- <u>Progress Energy's</u> Mayo plant is planning to convert their current bottom ash handling system to a PAX system (100 percent dry

¹⁶ 80 Fed. Reg. 67,852.

¹⁷ See Final Seminole Site Visit Notes, EPA-HQ-OW-2009-0819-1891 (Jan. 2013) (available at https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-1891).

¹⁸ See Memorandum to the Steam Electric Rulemaking Record: Ash Handling Documentation from Comunications with Clyde Bergemann Power Group, EPA-HQ-OW-2009-0819-6232 (Sep. 2015) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-6232).

vacuum), which is currently scheduled to be commissioned in 2013;

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UCC explained <u>that Duke Energy's</u> plants (i.e., Marshall, Allen, Wabash, and Gibson) are going dry to avoid violations, or risks of violations, with NPDES permits. Additionally, Duke Energy is exploring ash handling technologies in anticipation of changing regulations. Additionally, UCC reports that Gibson engaged UCC for quotes for a bottom ash handling conversion.

UCC also reported that <u>Progress Energy</u> wants to convert ash handling systems to dry to get ahead of the industry. UCC stated that Progress is likely going with a PAX bottom ash handling system for the plants that still operate wet sluicing systems. UCC stated that <u>this system because [*sid*</u>] operational at Crystal River 15 years ago.¹⁹

These notes show that DEF/PEF has already made significant progress on dry conversion for its plants/units, including not only installing such a system at its Mayo plant in 2013, but also for its other plants including CREC where only Units 4 and 5 use wet bottom ash sluicing. Moreover, the fact that these discussions took place in mid-2012 show that significant development work was completed on or before by that time—more than four years ago. The discussions also show significant preparations by DEF parent company to convert to dry handling systems in anticipation of the ELGs.

C. Utility Water Act Group (UWAG) Comments During the ELG Rule Development

Lastly, while numerous parties provided comments to the EPA during its ELG rulemaking, it is particularly important to note certain relevant portion of comments provided by the Utility water Act Group ("UWAG"), an industry consortium, which includes almost all utilities as its members.²⁰ Duke is a member of UWAG as was PEF.

In its comments, pertaining to bottom ash conversions, UWAG states that

¹⁹ See Teleconference Notes Between Kevin McDonough & Mike Kippis, United Conveyor Corporation, Ron Jordan and Jezebele Alicea-Virella, USEPA, TJ Finseth, Elizabeth Sabol, ERG, Inc., EPA-HQ-OW-2009-0819-0580 (May 24, 2012) (*available at* https://www.regulations.gov/document?D=EPA-HQ-OW-2009-0819-0580) (emphasis added).

²⁰ As UWAG's comment's note, "UWAG is a voluntary, *ad hoc*, non-profit, unincorporated group of 198 individual energy companies and three national trade associations of energy companies: the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers." Utility Water Act Group Comments on EPA's Proposed Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category, at 1 n.1.

[I]n the case study presented in the attachment, it would take 30-36 months to convert from a wet bottom ash hopper to a dry bottom ash hopper for a large unit.....Another case study for adding a remote wet ash hopper and submerged flight conveyor would take 27-33 months.²¹

The project implementation timeframes referenced in this section, which are already considerably shorter than what DEF has proposed (i.e., 44 months, as discussed in Section 7), are relevant for situations in which no initial planning or assessment has been completed. However, since, as shown next, there are clear indications that Duke Energy and PEF have undertaken significant, multi-year efforts to begin planning for a conversion to dry bottom ash handling, and that the implementation schedule at CREC Units 4 and 5 should be shorter.

6. DUKE ENERGY'S PUBLIC STATEMENTS AND PLANNING TO COMPLY WITH THE BOTTOM ASH ELGS

Public statements from Duke Energy corroborate that DEF has already evaluated options and developed likely costs for compliance with the ELGs at CREC Units 4 and 5, and that implementation can and should occur more quickly than in the schedules proposed by DEF and DEP.

A. Duke Energy's 2013 Annual Report and SEC Form 10-K Filing

In a brief discussion in its 2013 Annual Report, Duke Energy provided the following general statement, (although no cost estimates) regarding compliance with the then-proposed revised ELGs for steam electric power plants:

Steam Electric Effluent Limitation Guidelines

On June 7, 2013, the EPA proposed Steam Electric Effluent Limitations Guidelines (ELGs). The EPA is under a court order to finalize the rule by May 22, 2014. The EPA has proposed eight options for the rule, which vary in stringency and cost. The proposed regulation applies to seven waste streams, including wastewater from air pollution control equipment and ash transport water. Most, if not all of the steam electric generating facilities the Duke Energy Registrants own are likely affected sources. Compliance is proposed as soon as possible after July 1, 2017, but may extend until July 1, 2022. The Duke Energy Registrants are unable to predict the outcome of the rulemaking, but the impact

²¹ Id. at 84.

could be significant.22

B. Duke Energy's 2014 Annual Report and SEC Form 10-K Filing

Again in 2014, Duke Energy considered compliance with the proposed ELGs, this time offering cost estimates:

Steam Electric Effluent Limitation Guidelines

On June 7, 2013, the EPA proposed Steam Electric Effluent Limitations Guidelines. The EPA is under a revised court order to finalize the rule by September 30, 2015. The EPA has proposed eight options for the rule, which vary in stringency and cost. The proposed regulation applies to seven waste streams, including wastewater from air pollution control equipment and ash transport water. Most, if not all, of the steam electric generating facilities the Duke Energy Registrants own are likely affected sources. Requirements to comply with the Final rule may begin as early as late 2018 for some facilities.

Estimated Cost and Impacts of Rulemakings

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The following table provides estimated costs, excluding AFUDC, of new control equipment that may need to be installed on existing power plants, including conversion of plants to dry disposal of bottom ash and fly ash, to comply with the above regulations over the five years ended December 31, 2019

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(in millions)	Estimated Year Cost								
Duke Energy	\$	1,850							
Duke Energy Carolinas		875							
Progress Energy		525							
Duke Energy Progress		475							
Duke Energy Florida		50							
Duke Energy Ohio		75							
Duke Energy Indiana		575							

²² Available at <u>https://www.duke-energy.com/investors/financials-sec-filings/annual.asp</u>.

Even though the ELGs had not yet been finalized, Duke Energy recognized that the rule would likely be final by September 2015 and had already developed cost estimates for compliance. Duke Energy necessarily would have had to complete considerable planning and engineering work in the 2013-2014 time period to be able to share such cost estimates.

The statement above also shows that Duke anticipated that compliance would be required "as early as late 2018" which is consistent with EPA's final compliance schedule beginning in November 2018.

Specific to CREC units, the cost estimate of \$50 million presented to shareholders and the SEC for DEF relate directly to Units 4 and 5, since these are DEF's only non-retired coal units.

C. Duke Energy's 2015 Annual Report and SEC Form 10-K Filing

Finally, in 2015, Duke Energy again projected compliance dates and costs for the ELGs:

Steam Electric Effluent Limitations Guidelines

On January 4, 2016, the final Steam Electric Effluent Limitations Guidelines (ELG) rule became effective. The rule establishes new requirements for wastewater streams associated with steam electric power generation and includes more stringent controls for any new coal plants that may be built in the future. Affected facilities must comply between 2018 and 2023, depending on timing of new Clean Water Act permits. Most, if not all, of the steam electric generating facilities the Duke Energy Registrants own are likely affected sources. <u>The Duke Energy Registrants are well-</u> positioned to meet the requirements of the rule due to current <u>efforts to convert to dry ash handling.</u>

Estimated Cost and Impacts of Rulemakings

Duke Energy will incur capital expenditures to comply with the environmental regulations and rules discussed above. The following five-year table provides estimated costs, excluding AFUDC, of new control equipment that may need to be installed on existing power plants primarily to comply with the Coal Ash Act requirements for conversion to dry disposal of bottom ash and fly ash, MATS, Clean Water Act 316(b) and ELGs, through December 31, 2020.

²³ Duke Energy 2014 Annual Report at 59 *available at* https://www.duke-energy.com/investors/financials-sec-filings/annual.asp.

(in millions)	Five-Year Estimated Costs
Duke Energy	\$ 1,350
Duke Energy Carolinas	625
Progress Energy	350
Duke Energy Progress	300
Duke Energy Florida	50
Duke Energy Ohio	100
Duke Energy Indiana	275

The 2015 filing does not change the 2014 cost estimate of \$50 million for DEF's compliance with the ELGs, indicating no significant alterations in its compliance strategy. Notably, Duke Energy states that "[t]he Duke Energy Registrants are well-positioned to meet the requirements of the rule due to current efforts to convert to dry ash handling."²⁵ This statement is not surprising and is consistent with DEF's ability to meet a compliance deadline of late 2018.

7. CRITIQUE OF DEF'S PROPOSED COMPLIANCE SCHEDULE

As detailed above, Duke Energy and DEF have made considerable progress in preparations for compliance with the bottom ash wastewater provisions in the ELGs. Nothing in the record suggests that Units 4 and 5 cannot achieve compliance with the BAT requirements for bottom ash wastewater by November 1, 2018. Yet DEF has, surprisingly, proposed February 1, 2020, as the compliance deadline for the bottom ash BAT standard at CREC Units 4 and 5.

In its initial NPDES permit renewal application, DEF proposed the following schedule for "[e]valuation of the Dry Bottom Ash Dewatering system to eliminate the water overflows" and stated that "Duke Energy is in the process of conducting this evaluation:"²⁶

- Complete evaluation of the Dry Bottom Ash Dewatering System and submit to the Department a list of actions with deadlines July 31, 2018.
- Completion of actions and compliance with the ELG Rule no later than December 31, 2023.²⁷

²⁵ Id.

²⁶ Duke Energy Florida, Inc., Application to Renew NPDES Permit for Crystal River Units 4 & 5, Permit No. FL0036366, January 12, 2016, at attachment 4 p.1-2.

²⁷ Id.

²⁴ Duke Energy 2015 Annual Report at 63 *available at* <u>https://www.duke-energy.com/investors/financials-sec-filings/annual.asp</u> (emphasis added).

In other words, DEF did not commit to compliance before December 31, 2023, the final deadline for compliance with the revised ELGs, nor provide any support for why it would take until late 2023, eight years after the finalization of the ELGs.

Subsequently, in reponse to Florida DEP's request for additional information, DEF amended its initial proposed schedule for compliance and stated that:

DEF intends to promptly initiate the formal planning process on June 1, 2016, based on an assumption that the enclosed additional information will result in a complete application and no significant modification to DEF's compliance plans. Due to time needed for planning, procurement, permitting, construction and testing, DEF is requesting that the Department approve a date of completion February 1, 2020, 44 months from June 1, 2016.²⁸

DEF now proposes February 1, 2020, as the compliance deadline for the zero discharge standard for bottom ash wastewater. While this is an improvement over the previous, unsupported December 31, 2023, compliance date proposal, this is still too long, and not supported by an justification, as describe next.

As support for a project duration of 44 months, DEF provided a project schedule, shown below.²⁹

Task Number	Task Name	Duration (Months)
1	Bottom Ash Water Balance	6
2	Review Bottom Ash Modification Options	2
3	Finalize Bottom Ash Modification Options	3
4	Project Budget Approval	6
5	Detailed Engineering of Selected Modifications	3
6	Implementation of Modifications	18
7	Review of Modifications/Contingency	6
Total (month	ns - excluding task overlaps)	44

Table 1- CRN Unit 4 & 5 : Dry Bottom Ash

DEF's discussion of each Task Number, as shown in the schedule in F is provided below in

²⁸ Duke Energy Florida, Response to Request for Additional Information at 1, May 20, 2016.

²⁹ Duke Energy Florida, Response to Request for Additional Information, at attachment 1, May 20, 2016.

¹³⁸

italics followed by critique and commentary:

• Task 1 - Bottom Ash Water Balance Review

An internal water balance was developed on the bottom ash system several years ago and identified water streams and approximate amounts contributing to the bottom ash system. Review of the information on the on bottom ash system water balance will include verifying all streams indicated, data verification, and review of system as pertains to new ELG regulation. Approximately six (6) months are necessary to perform these actions, which provides time if additional information is required for the evaluation.

DEF asserts that an internal water balance must be developed, yet in its January 2016 application for NPDES permit renewal, just months ago, DEF provided a detailed water balance, as reproduced below.

The January 2016 renewal application was required be accurate and complete. Unless DEF failed to meet that requirement, which DEF has not indicated it has, DEF already has developed an accurate and complete water balance and should not need another six months to redevelop such a balance. Any verification needed can be made in a shorter time frame—and in parallel with the tasks described next. Thus, the six months built into the schedule for this task are a significant and unnecessary slack.



CRYSTAL RIVER UNITS 4 AND 5 WATER BALANCE

ITREAM NO.	0	1	0	10				Die)	0	10	94		(1)	(11)	12			3	1			1	1	2	2		34	25	3	1	1	910	0		916	010) () (010				۲		(m)
PLOW (KIPS)	1009	53			- 11	 U	804	- 10	100	100	823	78	28		411	878	87	4	38	15	28	-	1000	1780	568	-	78	101		78	82	82			1 1		4	 1	10	4	- 54	1	-	() in	19	-	(10)	800	840
HOW (IPM)	**		- 29		1		M	-	75	n	875	88	64	8	285	280	28		9	10	30	33	814	886	88	48	- 55	ni (48	10	kž į	87 3	4 0	10	. 2	< 0	1.4				10	R	1.9	#	21		dati	step	480

• Task 2 - Review Bottom Ash Modification Options

After review and finalization of a bottom ash water balance, a review of inputs and outputs will be performed. The review will indicate options available for managing the streams in the process. This could include a review of switching mechanical seals on pumps from wet to dry seals, evaluating rerouting streams to other locations, and system modifications required to meet the ELG regulations. The review of bottom ash modification options will last approximately two (2) months and will entail a review of possible pipe reroutes, potential changes in system operations, and system modifications required for ELG compliance.

• Task 3 - Finalize Bottom Ash Modification Options

Once DEF outlines the modification options, the next step is to determine which modifications and piping reroutes will needed. A three (3) month schedule is proposed for this activity, which includes review of modifications and reroutes from an economical, operational, and environmental standpoint with DEF's management team members with responsibility over these different functional areas. Additional time is included to resolve unexpected questions or missing data that may arise when finalizing the modification options considered in Task 2.

DEF's proposed 5-month duration for Tasks 2 and 3 to review and finalize bottom ash modification options is inexplicably long. So much time may be reasonable for a plant that has never before undertaken such reviews, but that is not the case here. Duke Energy already reported costs to the SEC and its shareholders for such modifications. It would be inconsistent with Duke's SEC and shareholder reporting obligations to report such costs without analytic support. Similar to Task 1, any further confirmation of Duke's options can be done in much less time. More specifically, if such confirmation is done in parallel with Task 1, any competent consultant, inhouse engineer, or vendor should be able to complete Tasks 1-3 in no more than 2 to 3 months, including development of a budget estimate, as discussed next.

• Task 4 - Budget Approval

The final modification plan will include appropriate budgetary estimates. In accordance with company fiduciary duties, DEF will conduct an in-depth financial review of these budgetary estimates prior to securing the requested funds. Depending on the budgetary amount required and the number of modifications necessary, several review stages may be required prior to fund approval. The project budget approval time is anticipated to last six (6) months.

DEF has already developed a budget estimate and Duke Energy has publicly reported this estimate since 2014. It is therefore unnecessary to schedule 6 additional months for budget approval. As Duke Energy's filing indicates, its Board has long been aware of the need to spend \$50 million for ELG compliance at CREC. Anticipated cost expenditures reported to shareholders are typically based on appropriate engineering and planning studies and analyses, including budgetary quotes obtained from vendors for equipment and labor. This is especially true for publicly traded corporations such as Duke Energy, which have significant legal obligations in its SEC filings. As a result, it is unreasonable to allow six additional months for internal budget approval.

• Task 5 - Detailed Engineering of Modifications

Once the modifications are selected and the budgetary approval finalized, the project will enter a detailed engineering design phase. This phase will likely include, but not limited to, pump sizing, pipe rerouting, vessel sizing, building additions or modifications, chemical sizing, system sizing, etc. An engineering firm may need to be identified and hired to help facilitate detailed engineering of the required modifications. DEF estimates it will take three (3) months to select an engineering firm with the requisite expertize and then work with the firm to finalize the detailed engineering design.

If DEF were to hire the same engineering firm or consultant to confirm Tasks 1, 2, and 3, Task 5 can be run in parallel with those tasks, saving more time. Alternatively, Duke could save as much if not even more time if DEF were to complete Tasks 1, 2, 3, and 5 with in-house engineering staff and/or Duke's corporate engineering staff.

• Task 6 - Implementation of Modifications

Depending on bottom ash system modifications selected, construction or implementation may or may not be an extensive process. The ideal modifications selected would have minimal capital and operational and maintenance cost associated with them. However, lead times on components and routing of streams to alternative locations may nevertheless prolong the estimated duration, as well as, any unforeseen circumstances such as weather. Some modifications may require a unit outage to complete. Recognizing the current uncertainty associated with implementing plant modifications that have not yet been conceived, DEF conservatively estimates that eighteen (18) months will be required to retain a labor and construction firm to perform the selected modifications from Task 5 and includes time to implement modifications that may require a long term outage.

Depending on the option selected, "implementation may or may not be an extensive process..." Thus, the possibility that this task will take 18 months, is a worst case estimate, with enough contingency already built in. For example, if DEF chooses to not replace the current almost closed loop system with a complete dry system, and instead chooses to engineer and build additional margin so that there is no possibility of any overflow of the bottom ash transport water under any circumstances to receiving waters, then implementation will likely take significantly less time.

• Task 7 - Review of Modifications/Contingency

Approximately six (6) months have been added to the compliance schedule for review of system modifications and/or contingency needed due to unforeseen events that may arise in other tasks. If the dry bottom ash system modifications have unintended or undesirable impacts on other processes or do not obtain satisfactory results, then additional modifications and reviews may be required to resolve.

DEF's proposal of six months of additional contingency, on top of the contingency already built into Task 6, is simply unjustified additional slack in the schedule.

In summary, Tasks 1-5 can be reasonably completed in 6 to 9 months, if not less. Even assuming that Task 6 takes all of 18 months, which is highly unlikely, and allowing for a reasonable contingency of 3 months in Task 7, the overall project duration should be in the range of 27 to 30 months, instead of the 44 months projected by DEF, a saving of 17 months. This would allow compliance to be achieved by roughly August to November 2018. DEP should carefully review the unsupported schedule provided by DEF and, reasonably, require that Units 4 and 5 achieve bottom ash wastewater BAT compliance by no later than November 2018.

8. COMPARISON OF DEF'S COMPLIANCE SCHEDULE WITH THAT OF OTHER LARGE PROJECTS

DEF's 44-month schedule to achieve compliance with the bottom ash wastewater BAT provisions of the ELGs is simply unsupported. In part, this is due to DEF's unjustified and long projected timelines for certain tasks, particularly given the strong evidence of DEF and Duke's prior planning for compliance with these provisions, which began as far back as mid-2012.

Additionally, in comparison to other major projects at coal-fired units, the 44-month schedule proposed by DEF for bottom ash ELG BAT compliance is simply unreasonable and too long. Here, comparisons are made using the expected timelines for implementing complex,air pollution control projects at coal-fired boilers. These include the installation of wet or dry flue gas desulfurization ("FGD") or scrubbers for SO₂ control and the installation of Selective Catalytic Reduction ("SCR") for NOx control. These projects, for units of similar size to CREC Units 4 and 5, often cost hundreds of million dollars. Yet, while often complex and challenging to implement, timelines for such projects are in the range of 3 to 5 years—starting from conceptual engineering through completion during scheduled outages.

Three example timelines are shown below—for dry FGD, wet FGD, and SCR projects, respectively—as developed by a contractor for MISO, the independent system operator for the U.S..³⁰ These timelines are generally conservative—i.e., the timelines shown are generally high, reflecting the most complex installations, with typical projects capable of implementation in less time. Nonetheless, as the charts below show, the expected durations for implementing dry FGD or SCR are around 46 months and the same for wet FGD is around 56 months.

Given the far greater complexity associated with these projects, DEF's assertion is untenable that the relatively much simpler conversion of Unit 4 and Unit 5's wet sluicing bottom ash system to a dry system will take 44 months. If DEF decides to achieve compliance without

³⁰ The Brattle Group, *Supply Chain and Outage Analysis of MISO Coal Retrofits for MATS*, Appendix A (May 2012) (available at http://www.brattle.com/news-and-knowledge/news/brattle-economists-identify-challenges-for-miso-s-coal-fleet-to-comply-with-epa-s-mats-rule).

¹⁴³

switching to a dry system, implementation times will be even shorter.

•				•								1																		
Dry FGD																														
Project Phase	0	2	4	6	8	10	12	14	16 1	8 20	22	2 24	26	28	30	32	34	36	38	40	42 -	44	46	48	50	52	54	56	58	60
Permitting																														
Design Engineering																														
System Interface / Site Engineering																														
Procurement																														
Construction																														
Testing																														
Outage																														
Wet FGD																														
Project Phase	0	2	4	6	8	10	12	14	16 1	8 20) 22	2 24	26	28	30	32	34	36	38	40	42 -	44	46	48	50	52	54	56	58	60
Permitting																														
Design Engineering																														
SystemInterface / Site Engineering																														
Procurement																														
Construction																														
Testing																														
Outage																														
SCR																														
Project Phase	0	2	4	6	8	1	0 12	2 14	16	18	20	22	24 2	26 2	28 :	30 3	32 3	34 3	36 3	38 4	40 4	12 4	14 4	46	48	50	52	54	56	58 6
Permitting																														
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Typical Timelines for Dry FGD, Wet FGD, DSI and ACI Retrofit Projects

9. CONCLUSIONS

DEF does not need till February 1, 2020 to achieve compliance with a zero discharge standard for bottom ash wastewater at CREC Units 4 and 5. Rather, compliance can be achieved by November 2018, if not sooner.

Construction for bottom ash retrofits at Units 4 and 5 is anticipated to take, with a built in contingency, only 18 months. Other proposed tasks for acheving compliance should take significantly less time than DEF forecasts, particularly as DEF began ancticipating and planning for the revised ELGs as far back as 2012. Beginning in 2014, Duke Energy began publicly reporting projected compliance costs, suggesting that conceptual or detailed engineering evaluations and studies were undertaken and that Duke Energy's Board has been aware of these changes and costs for some time.

DEF's 44-month schedule to achieve compliance with the bottom ash BAT standard is

simply unsupported. Comparisons to similar retrofits and other large-scale, more complex projects at coal-burning units show far shorter timelines and demonstrate that DEF's proposed schedule is inflated. Moreover, as DEF is aware, there is a robust vendor community with experience in handling the types of retrofits needed to achieve compliance.

The available evidence does not support a 44-month timeline for eliminating bottom ash wastewtater discharges at CREC Units 4 and 5. In renewing the NPDES permit for CREC Units 4 and 5, DEP should require DEF to achieve compliance with the bottom ash wastewater ELGs no later than November 2018.

10. AUTHOR'S EXPERTISE AND QUALIFICATIONS

Dr. Ranajit Sahu has over twenty-five years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

Over the last twenty-three years, Dr. Sahu has consulted on several municipal landfill related projects addressing landfill gas generation, landfill gas collection, and the treatment/disposal/control of such gases in combustion equipment such as engines, turbines, and flares. In particular, Dr. Sahu has executed numerous projects relating to flare emissions from sources such as landfills as well as refineries and chemical plants. He has served as a peer-reviewer for EPA in relation to flare combustion efficiency, flare destruction efficiency, and flaring emissions.

A significant portion of Dr. Sahu's educational background and consulting experience deals with addressing environmental impacts due to coal-fired power plants including all aspects of air emissions from such plants but also environmental impacts from water/waste water, cooling water, and solid/hazardous wastes at such plants and impacts due to coal mining, transportation, and stockpiling.

Dr. Sahu holds a B.S., M.S., and Ph.D., in Mechanical Engineering, the first from the Indian Institute of Technology (Kharagpur, India) and the latter two from the California Institute of Technology (Caltech) in Pasadena, California. His research specialization was in the combustion of coal and, among other things, understanding air pollution aspects of coal combustion in power plants as well as the formation of ash during combustion.

The opinions expressed in the report are Dr. Sahu's and are based on the data and facts available at the time of writing. Should additional relevant or pertinent information become available, Dr. Sahu reserves the right to supplement the discussion and findings.

ATTACHMENT A - RESUME

RANAJIT (RON) SAHU, Ph.D, QEP, CEM (Nevada)

CONSULTANT, ENVIRONMENTAL AND ENERGY ISSUES 311 North Story Place Alhambra, CA 91801 Phone: 702.683.5466 e-mail (preferred): sahuron@earthlink.net

EXPERIENCE SUMMARY

Dr. Sahu has over twenty five years of experience in the fields of environmental, mechanical, and chemical engineering including: program and project management services; design and specification of pollution control equipment for a wide range of emissions sources; soils and groundwater remediation including landfills as remedy; combustion engineering evaluations; energy studies; multimedia environmental regulatory compliance (involving statutes and regulations such as the Federal CAA and its Amendments, Clean Water Act, TSCA, RCRA, CERCLA, SARA, OSHA, NEPA as well as various related state statutes); transportation air quality impact analysis; multimedia compliance audits; multimedia permitting (including air quality NSR/PSD permitting, Title V permitting, NPDES permitting for industrial and storm water discharges, RCRA permitting, etc.), multimedia/multi-pathway human health risk assessments for toxics; air dispersion modeling; and regulatory strategy development and support including negotiation of consent agreements and orders.

Specifically, over the last twenty-three years, Dr. Sahu has consulted on several municipal landfill related projects addressing landfill gas generation, landfill gas collection, and the treatment/disposal/control of such gases in combustion equipment such as engines, turbines, and flares. In particular, Dr. Sahu has executed numerous projects relating to flare emissions from sources such as landfills as well as refineries and chemical plants. He has served as a peer-reviewer for EPA in relation to flare combustion efficiency, flare destruction efficiency, and flaring emissions.

A significant portion of Dr. Sahu's educational background and consulting experience deals with addressing environmental impacts due to coal-fired power plants including all aspects of air emissions from such plants but also environmental impacts from water/waste water, cooling water, and solid/hazardous wastes at such plants and impacts due to coal mining, transportation, and stockpiling.

Dr. Sahu holds a B.S., M.S., and Ph.D., in Mechanical Engineering, the first from the Indian Institute of Technology (Kharagpur, India) and the latter two from the California Institute of Technology (Caltech) in Pasadena, California. His research specialization was in the combustion of coal and, among other things, understanding air pollution aspects of coal combustion in power plants as well as the formation of ash during combustion. He has over twenty-three years of project management experience and has successfully managed and executed numerous projects in this time period. This includes basic and applied research projects, design projects, regulatory compliance projects, permitting projects, energy studies, risk assessment projects, and projects involving the communication of environmental data and information to the public. Notably, he has successfully managed a complex soils and groundwater remediation project with a value of over \$140 million involving soils characterization, development and implementation of the remediation strategy including construction of a CAMU/landfill and associated groundwater monitoring, regulatory and public interactions and other challenges.

He has provided consulting services to numerous private sector, public sector and public interest group clients. His major clients over the past twenty three years include various steel mills, petroleum refineries, cement companies, aerospace companies, power generation facilities, lawn and garden equipment manufacturers, spa manufacturers, chemical distribution facilities, and various entities in the public sector including EPA, the US Dept. of Justice, California DTSC, various municipalities, etc.). Dr. Sahu has performed projects in over 44 states, numerous local jurisdictions and internationally.

In addition to consulting, Dr. Sahu has taught numerous courses in several Southern California universities including UCLA (air pollution), UC Riverside (air pollution, process hazard analysis), and Loyola Marymount University (air pollution, risk assessment, hazardous waste management) for the past seventeen years. In this time period he has also taught at Caltech, his alma mater (various engineering courses), at the University of Southern California (air pollution controls) and at California State University, Fullerton (transportation and air quality).

Dr. Sahu has and continues to provide expert witness services in a number of environmental areas discussed above in both state and Federal courts as well as before administrative bodies.

EXPERIENCE RECORD

- 2000-present **Independent Consultant.** Providing a variety of private sector (industrial companies, land development companies, law firms, etc.) public sector (such as the US Department of Justice) and public interest group clients with project management, air quality consulting, waste remediation and management consulting, as well as regulatory and engineering support consulting services.
- 1995-2000 Parsons ES, Associate, Senior Project Manager and Department Manager for Air Quality/Geosciences/Hazardous Waste Groups, Pasadena. Responsible for the management of a group of approximately 24 air quality and environmental professionals, 15 geoscience, and 10 hazardous waste professionals providing fullservice consulting, project management, regulatory compliance and A/E design assistance in all areas.

Parsons ES, **Manager for Air Source Testing Services**. Responsible for the management of 8 individuals in the area of air source testing and air regulatory permitting projects located in Bakersfield, California.

- 1992-1995 Engineering-Science, Inc. **Principal Engineer and Senior Project Manager** in the air quality department. Responsibilities included multimedia regulatory compliance and permitting (including hazardous and nuclear materials), air pollution engineering (emissions from stationary and mobile sources, control of criteria and air toxics, dispersion modeling, risk assessment, visibility analysis, odor analysis), supervisory functions and project management.
- 1990-1992 Engineering-Science, Inc. **Principal Engineer and Project Manager** in the air quality department. Responsibilities included permitting, tracking regulatory issues, technical analysis, and supervisory functions on numerous air, water, and hazardous waste projects. Responsibilities also include client and agency interfacing, project cost and schedule control, and reporting to internal and external upper management regarding project status.
- 1989-1990 Kinetics Technology International, Corp. **Development Engineer.** Involved in thermal engineering R&D and project work related to low-NOx ceramic radiant burners, fired heater NOx reduction, SCR design, and fired heater retrofitting.
- 1988-1989 Heat Transfer Research, Inc. **Research Engineer**. Involved in the design of fired heaters, heat exchangers, air coolers, and other non-fired equipment. Also did research in the area of heat exchanger tube vibrations.

EDUCATION

- 1984-1988 Ph.D., Mechanical Engineering, California Institute of Technology (Caltech), Pasadena, CA.
- 1984 M. S., Mechanical Engineering, Caltech, Pasadena, CA.
- 1978-1983 B. Tech (Honors), Mechanical Engineering, Indian Institute of Technology (IIT) Kharagpur, India

TEACHING EXPERIENCE

<u>Caltech</u>

"Thermodynamics," Teaching Assistant, California Institute of Technology, 1983, 1987.

"Air Pollution Control," Teaching Assistant, California Institute of Technology, 1985.

"Caltech Secondary and High School Saturday Program," - taught various mathematics (algebra through calculus) and science (physics and chemistry) courses to high school students, 1983-1989.

- "Heat Transfer," taught this course in the Fall and Winter terms of 1994-1995 in the Division of Engineering and Applied Science.
- "Thermodynamics and Heat Transfer," Fall and Winter Terms of 1996-1997.

U.C. Riverside, Extension

- "Toxic and Hazardous Air Contaminants," University of California Extension Program, Riverside, California. Various years since 1992.
- "Prevention and Management of Accidental Air Emissions," University of California Extension Program, Riverside, California. Various years since 1992.
- "Air Pollution Control Systems and Strategies," University of California Extension Program, Riverside, California, Summer 1992-93, Summer 1993-1994.
- "Air Pollution Calculations," University of California Extension Program, Riverside, California, Fall 1993-94, Winter 1993-94, Fall 1994-95.
- "Process Safety Management," University of California Extension Program, Riverside, California. Various years since 1992-2010.
- "Process Safety Management," University of California Extension Program, Riverside, California, at SCAQMD, Spring 1993-94.
- "Advanced Hazard Analysis A Special Course for LEPCs," University of California Extension Program, Riverside, California, taught at San Diego, California, Spring 1993-1994.
- "Advanced Hazardous Waste Management" University of California Extension Program, Riverside, California. 2005.

Loyola Marymount University

- "Fundamentals of Air Pollution Regulations, Controls and Engineering," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1993.
- "Air Pollution Control," Loyola Marymount University, Dept. of Civil Engineering, Fall 1994.
- "Environmental Risk Assessment," Loyola Marymount University, Dept. of Civil Engineering. Various years since 1998.
- "Hazardous Waste Remediation" Loyola Marymount University, Dept. of Civil Engineering. Various years since 2006.

University of Southern California

"Air Pollution Controls," University of Southern California, Dept. of Civil Engineering, Fall 1993, Fall 1994.

"Air Pollution Fundamentals," University of Southern California, Dept. of Civil Engineering, Winter 1994.

University of California, Los Angeles

"Air Pollution Fundamentals," University of California, Los Angeles, Dept. of Civil and Environmental Engineering, Spring 1994, Spring 1999, Spring 2000, Spring 2003, Spring 2006, Spring 2007, Spring 2008, Spring 2009.

International Programs

- "Environmental Planning and Management," 5 week program for visiting Chinese delegation, 1994.
- "Environmental Planning and Management," 1 day program for visiting Russian delegation, 1995.

"Air Pollution Planning and Management," IEP, UCR, Spring 1996.

"Environmental Issues and Air Pollution," IEP, UCR, October 1996.

PROFESSIONAL AFFILIATIONS AND HONORS

President of India Gold Medal, IIT Kharagpur, India, 1983.

- Member of the Alternatives Assessment Committee of the Grand Canyon Visibility Transport Commission, established by the Clean Air Act Amendments of 1990, 1992-present.
- American Society of Mechanical Engineers: Los Angeles Section Executive Committee, Heat Transfer Division, and Fuels and Combustion Technology Division, 1987-present.

Air and Waste Management Association, West Coast Section, 1989-present.

PROFESSIONAL CERTIFICATIONS

EIT, California (# XE088305), 1993.

REA I, California (#07438), 2000.

Certified Permitting Professional, South Coast AQMD (#C8320), since 1993.

QEP, Institute of Professional Environmental Practice, since 2000.

CEM, State of Nevada (#EM-1699). Expiration 10/07/2017.

ATTACHMENT B – LIST OF PUBLICATIONS AND PRESENTATIONS

PUBLICATIONS (PARTIAL LIST)

"Physical Properties and Oxidation Rates of Chars from Bituminous Coals," with Y.A. Levendis, R.C. Flagan and G.R. Gavalas, *Fuel*, **67**, 275-283 (1988).

"Char Combustion: Measurement and Analysis of Particle Temperature Histories," with R.C. Flagan, G.R. Gavalas and P.S. Northrop, *Comb. Sci. Tech.* **60**, 215-230 (1988).

"On the Combustion of Bituminous Coal Chars," PhD Thesis, California Institute of Technology (1988).

"Optical Pyrometry: A Powerful Tool for Coal Combustion Diagnostics," J. Coal Quality, 8, 17-22 (1989).

"Post-Ignition Transients in the Combustion of Single Char Particles," with Y.A. Levendis, R.C.Flagan and G.R. Gavalas, *Fuel*, **68**, 849-855 (1989).

"A Model for Single Particle Combustion of Bituminous Coal Char." Proc. ASME National Heat Transfer Conference, Philadelphia, **HTD-Vol. 106**, 505-513 (1989).

"Discrete Simulation of Cenospheric Coal-Char Combustion," with R.C. Flagan and G.R.Gavalas, *Combust. Flame*, **77**, 337-346 (1989).

"Particle Measurements in Coal Combustion," with R.C. Flagan, in "**Combustion Measurements**" (ed. N. Chigier), Hemisphere Publishing Corp. (1991).

"Cross Linking in Pore Structures and Its Effect on Reactivity," with G.R. Gavalas in preparation.

"Natural Frequencies and Mode Shapes of Straight Tubes," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Optimal Tube Layouts for Kamui SL-Series Exchangers," with K. Ishihara, Proprietary Report for Kamui Company Limited, Tokyo, Japan (1990).

"HTRI Process Heater Conceptual Design," Proprietary Report for Heat Transfer Research Institute, Alhambra, CA (1990).

"Asymptotic Theory of Transonic Wind Tunnel Wall Interference," with N.D. Malmuth and others, Arnold Engineering Development Center, Air Force Systems Command, USAF (1990).

"Gas Radiation in a Fired Heater Convection Section," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1990).

"Heat Transfer and Pressure Drop in NTIW Heat Exchangers," Proprietary Report for Heat Transfer Research Institute, College Station, TX (1991).

"NOx Control and Thermal Design," Thermal Engineering Tech Briefs, (1994).

"From Puchase of Landmark Environmental Insurance to Remediation: Case Study in Henderson, Nevada," with Robin E. Bain and Jill Quillin, presented at the AQMA Annual Meeting, Florida, 2001.

"The Jones Act Contribution to Global Warming, Acid Rain and Toxic Air Contaminants," with Charles W. Botsford, presented at the AQMA Annual Meeting, Florida, 2001.

PRESENTATIONS (PARTIAL LIST)

"Pore Structure and Combustion Kinetics - Interpretation of Single Particle Temperature-Time Histories," with P.S. Northrop, R.C. Flagan and G.R. Gavalas, presented at the AIChE Annual Meeting, New York (1987).

"Measurement of Temperature-Time Histories of Burning Single Coal Char Particles," with R.C. Flagan, presented at the American Flame Research Committee Fall International Symposium, Pittsburgh, (1988).

"Physical Characterization of a Cenospheric Coal Char Burned at High Temperatures," with R.C. Flagan and G.R. Gavalas, presented at the Fall Meeting of the Western States Section of the Combustion Institute, Laguna Beach, California (1988).

"Control of Nitrogen Oxide Emissions in Gas Fired Heaters - The Retrofit Experience," with G. P. Croce and R. Patel, presented at the International Conference on Environmental Control of Combustion Processes (Jointly sponsored by the American Flame Research Committee and the Japan Flame Research Committee), Honolulu, Hawaii (1991).

"Air Toxics - Past, Present and the Future," presented at the Joint AIChE/AAEE Breakfast Meeting at the AIChE 1991 Annual Meeting, Los Angeles, California, November 17-22 (1991).

"Air Toxics Emissions and Risk Impacts from Automobiles Using Reformulated Gasolines," presented at the Third Annual Current Issues in Air Toxics Conference, Sacramento, California, November 9-10 (1992).

"Air Toxics from Mobile Sources," presented at the Environmental Health Sciences (ESE) Seminar Series, UCLA, Los Angeles, California, November 12, (1992).

"Kilns, Ovens, and Dryers - Present and Future," presented at the Gas Company Air Quality Permit Assistance Seminar, Industry Hills Sheraton, California, November 20, (1992).

"The Design and Implementation of Vehicle Scrapping Programs," presented at the 86th Annual Meeting of the Air and Waste Management Association, Denver, Colorado, June 12, 1993.

"Air Quality Planning and Control in Beijing, China," presented at the 87th Annual Meeting of the Air and Waste Management Association, Cincinnati, Ohio, June 19-24, 1994.

ATTACHMENT C – PREVIOUS EXPERT WITNESS TESTIMONY

1. Occasions where Dr. Sahu has provided Written or Oral testimony before Congress:

(a) In July 2012, provided expert written and oral testimony to the House Subcommittee on Energy and the Environment, Committee on Science, Space, and Technology at a Hearing entitled "Hitting the Ethanol Blend Wall – Examining the Science on E15."

2. Matters for which Dr. Sahu has provided affidavits and expert reports include:

- (b) Affidavit for Rocky Mountain Steel Mills, Inc. located in Pueblo Colorado dealing with the technical uncertainties associated with night-time opacity measurements in general and at this steel mini-mill.
- (c) Expert reports and depositions (2/28/2002 and 3/1/2002; 12/2/2003 and 12/3/2003; 5/24/2004) on behalf of the United States in connection with the Ohio Edison NSR Cases. United States, et al. v. Ohio Edison Co., et al., C2-99-1181 (Southern District of Ohio).
- (d) Expert reports and depositions (5/23/2002 and 5/24/2002) on behalf of the United States in connection with the Illinois Power NSR Case. United States v. Illinois Power Co., et al., 99-833-MJR (Southern District of Illinois).
- (e) Expert reports and depositions (11/25/2002 and 11/26/2002) on behalf of the United States in connection with the Duke Power NSR Case. *United States, et al. v. Duke Energy Corp.*, 1:00-CV-1262 (Middle District of North Carolina).
- (f) Expert reports and depositions (10/6/2004 and 10/7/2004; 7/10/2006) on behalf of the United States in connection with the American Electric Power NSR Cases. United States, et al. v. American Electric Power Service Corp., et al., C2-99-1182, C2-99-1250 (Southern District of Ohio).
- (g) Affidavit (March 2005) on behalf of the Minnesota Center for Environmental Advocacy and others in the matter of the Application of Heron Lake BioEnergy LLC to construct and operate an ethanol production facility submitted to the Minnesota Pollution Control Agency.
- (h) Expert Report and Deposition (10/31/2005 and 11/1/2005) on behalf of the United States in connection with the East Kentucky Power Cooperative NSR Case. United States v. East Kentucky Power Cooperative, Inc., 5:04-cv-00034-KSF (Eastern District of Kentucky).
- (i) Affidavits and deposition on behalf of Basic Management Inc. (BMI) Companies in connection with the BMI vs. USA remediation cost recovery Case.
- (j) Expert Report on behalf of Penn Future and others in the Cambria Coke plant permit challenge in Pennsylvania.

- (k) Expert Report on behalf of the Appalachian Center for the Economy and the Environment and others in the Western Greenbrier permit challenge in West Virginia.
- (l) Expert Report, deposition (via telephone on January 26, 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) in the Thompson River Cogeneration LLC Permit No. 3175-04 challenge.
- (m) Expert Report and deposition (2/2/07) on behalf of the Texas Clean Air Cities Coalition at the Texas State Office of Administrative Hearings (SOAH) in the matter of the permit challenges to TXU Project Apollo's eight new proposed PRB-fired PC boilers located at seven TX sites.
- (n) Expert Testimony (July 2007) on behalf of the Izaak Walton League of America and others in connection with the acquisition of power by Xcel Energy from the proposed Gascoyne Power Plant – at the State of Minnesota, Office of Administrative Hearings for the Minnesota PUC (MPUC No. E002/CN-06-1518; OAH No. 12-2500-17857-2).
- (o) Affidavit (July 2007) Comments on the Big Cajun I Draft Permit on behalf of the Sierra Club submitted to the Louisiana DEQ.
- (p) Expert Report and Deposition (12/13/2007) on behalf of Commonwealth of Pennsylvania Dept. of Environmental Protection, State of Connecticut, State of New York, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case. *Plaintiffs v. Allegheny Energy Inc., et al.*, 2:05cv0885 (Western District of Pennsylvania).
- (q) Expert Reports and Pre-filed Testimony before the Utah Air Quality Board on behalf of Sierra Club in the Sevier Power Plant permit challenge.
- (r) Expert Report and Deposition (October 2007) on behalf of MTD Products Inc., in connection with *General Power Products, LLC v MTD Products Inc.*, 1:06 CVA 0143 (Southern District of Ohio, Western Division).
- (s) Expert Report and Deposition (June 2008) on behalf of Sierra Club and others in the matter of permit challenges (Title V: 28.0801-29 and PSD: 28.0803-PSD) for the Big Stone II unit, proposed to be located near Milbank, South Dakota.
- (t) Expert Reports, Affidavit, and Deposition (August 15, 2008) on behalf of Earthjustice in the matter of air permit challenge (CT-4631) for the Basin Electric Dry Fork station, under construction near Gillette, Wyoming before the Environmental Quality Council of the State of Wyoming.
- (u) Affidavits (May 2010/June 2010 in the Office of Administrative Hearings))/Declaration and Expert Report (November 2009 in the Office of Administrative Hearings) on behalf of NRDC and the Southern Environmental Law Center in the matter of the air permit challenge for Duke

Cliffside Unit 6. Office of Administrative Hearing Matters 08 EHR 0771, 0835 and 0836 and 09 HER 3102, 3174, and 3176 (consolidated).

- (v) Declaration (August 2008), Expert Report (January 2009), and Declaration (May 2009) on behalf of Southern Alliance for Clean Energy in the matter of the air permit challenge for Duke Cliffside Unit 6. Southern Alliance for Clean Energy et al., v. Duke Energy Carolinas, LLC, Case No. 1:08-cv-00318-LHT-DLH (Western District of North Carolina, Asheville Division).
- (w) Declaration (August 2008) on behalf of the Sierra Club in the matter of Dominion Wise County plant MACT.us
- (x) Expert Report (June 2008) on behalf of Sierra Club for the Green Energy Resource Recovery Project, MACT Analysis.
- (y) Expert Report (February 2009) on behalf of Sierra Club and the Environmental Integrity Project in the matter of the air permit challenge for NRG Limestone's proposed Unit 3 in Texas.
- (z) Expert Report (June 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*
- (aa) Expert Report (August 2009) on behalf of Sierra Club and the Southern Environmental Law Center in the matter of the air permit challenge for Santee Cooper's proposed Pee Dee plant in South Carolina).
- (bb) Statements (May 2008 and September 2009) on behalf of the Minnesota Center for Environmental Advocacy to the Minnesota Pollution Control Agency in the matter of the Minnesota Haze State Implementation Plans.
- (cc) Expert Report (August 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
- (dd) Expert Report and Rebuttal Report (September 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.
- (ee) Expert Report (December 2009) and Rebuttal reports (May 2010 and June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. United States v. Alabama Power Company, CV-01-HS-152-S (Northern District of Alabama, Southern Division).
- (ff) Pre-filed Testimony (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).

- (gg) Pre-filed Testimony (July 2010) and Written Rebuttal Testimony (August 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – Greenhouse Gas Cap and Trade Provisions, No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.
- (hh) Expert Report (August 2010) and Rebuttal Expert Report (October 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. United States v. Louisiana Generating, LLC, 09-CV100-RET-CN (Middle District of Louisiana) – Liability Phase.
- (ii) Declaration (August 2010), Reply Declaration (November 2010), Expert Report (April 2011), Supplemental and Rebuttal Expert Report (July 2011) on behalf of the United States in the matter of DTE Energy Company and Detroit Edison Company (Monroe Unit 2). United States of America v. DTE Energy Company and Detroit Edison Company, Civil Action No. 2:10-cv-13101-BAF-RSW (Eastern District of Michigan).
- (jj) Expert Report and Deposition (August 2010) as well as Affidavit (September 2010) on behalf of Kentucky Waterways Alliance, Sierra Club, and Valley Watch in the matter of challenges to the NPDES permit issued for the Trimble County power plant by the Kentucky Energy and Environment Cabinet to Louisville Gas and Electric, File No. DOW-41106-047.
- (kk) Expert Report (August 2010), Rebuttal Expert Report (September 2010), Supplemental Expert Report (September 2011), and Declaration (November 2011) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (District of Colorado).
- (ll) Written Direct Expert Testimony (August 2010) and Affidavit (February 2012) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).
- (mm) Deposition (August 2010) on behalf of Environmental Defense, in the matter of the remanded permit challenge to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
- (nn) Expert Report, Supplemental/Rebuttal Expert Report, and Declarations (October 2010, November 2010, September 2012) on behalf of New Mexico Environment Department (Plaintiff-Intervenor), Grand Canyon Trust and Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. Public Service Company of New Mexico* (PNM), Civil No. 1:02-CV-0552 BB/ATC (ACE) (District of New Mexico).
- (00) Expert Report (October 2010) and Rebuttal Expert Report (November 2010) (BART Determinations for PSCo Hayden and CSU Martin Drake units) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.
- (pp) Expert Report (November 2010) (BART Determinations for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) to the Colorado Air Quality Commission on behalf of Coalition of Environmental Organizations.
- (qq) Declaration (November 2010) on behalf of the Sierra Club in connection with the Martin Lake Station Units 1, 2, and 3. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Case No. 5:10-cv-00156-DF-CMC (Eastern District of Texas, Texarkana Division).
- (rr) Pre-Filed Testimony (January 2011) and Declaration (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).
- (ss) Declaration (February 2011) in the matter of the Draft Title V Permit for RRI Energy MidAtlantic Power Holdings LLC Shawville Generating Station (Pennsylvania), ID No. 17-00001 on behalf of the Sierra Club.
- (tt) Expert Report (March 2011), Rebuttal Expert Report (June 2011) on behalf of the United States in United States of America v. Cemex, Inc., Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).
- (uu) Declaration (April 2011) and Expert Report (July 16, 2012) in the matter of the Lower Colorado River Authority (LCRA)'s Fayette (Sam Seymour) Power Plant on behalf of the Texas Campaign for the Environment. *Texas Campaign for the Environment v. Lower Colorado River Authority*, Civil Action No. 4:11-cv-00791 (Southern District of Texas, Houston Division).
- (vv) Declaration (June 2011) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.
- (ww) Expert Report (June 2011) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).
- (xx) Declaration (August 2011) in the matter of the Sandy Creek Energy Associates L.P. Sandy Creek Power Plant on behalf of Sierra Club and Public Citizen. Sierra Club, Inc. and Public Citizen, Inc. v. Sandy Creek Energy Associates, L.P., Civil Action No. A-08-CA-648-LY (Western District of Texas, Austin Division).
- (yy) Expert Report (October 2011) on behalf of the Defendants in the matter of John Quiles and Jeanette Quiles et al. v. Bradford-White Corporation, MTD Products, Inc., Kohler Co., et al., Case No. 3:10-cv-747 (TJM/DEP) (Northern District of New York).

- (zz) Declaration (February 2012) and Second Declaration (February 2012) in the matter of Washington Environmental Council and Sierra Club Washington State Chapter v. Washington State Department of Ecology and Western States Petroleum Association, Case No. 11-417-MJP (Western District of Washington).
- (aaa) Expert Report (March 2012) and Supplemental Expert Report (November 2013) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.*, Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).
- (bbb) Declaration (March 2012) in the matter of *Center for Biological Diversity, et al. v. United States Environmental Protection Agency,* Case No. 11-1101 (consolidated with 11-1285, 11-1328 and 11-1336) (US Court of Appeals for the District of Columbia Circuit).
- (ccc) Declaration (March 2012) in the matter of *Sierra Club v. The Kansas Department of Health and Environment*, Case No. 11-105,493-AS (Holcomb power plant) (Supreme Court of the State of Kansas).
- (ddd) Declaration (March 2012) in the matter of the Las Brisas Energy Center Environmental Defense Fund et al., v. Texas Commission on Environmental Quality, Cause No. D-1-GN-11-001364 (District Court of Travis County, Texas, 261st Judicial District).
- (eee) Expert Report (April 2012), Supplemental and Rebuttal Expert Report (July 2012), and Supplemental Rebuttal Expert Report (August 2012) on behalf of the states of New Jersey and Connecticut in the matter of the Portland Power plant State of New Jersey and State of Connecticut (Intervenor-Plaintiff) v. RRI Energy Mid-Atlantic Power Holdings et al., Civil Action No. 07-CV-5298 (JKG) (Eastern District of Pennsylvania).
- (fff) Declaration (April 2012) in the matter of the EPA's EGU MATS Rule, on behalf of the Environmental Integrity Project.
- (ggg) Expert Report (August 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. United States v. Louisiana Generating, LLC, 09-CV100-RET-CN (Middle District of Louisiana) Harm Phase.
- (hhh) Declaration (September 2012) in the Matter of the Application of *Energy Answers Incinerator*, *Inc.* for a Certificate of Public Convenience and Necessity to Construct a 120 MW Generating Facility in Baltimore City, Maryland, before the Public Service Commission of Maryland, Case No. 9199.
- (iii) Expert Report (October 2012) on behalf of the Appellants (Robert Concilus and Leah Humes) in the matter of Robert Concilus and Leah Humes v. Commonwealth of Pennsylvania Department of Environmental Protection and Crawford Renewable Energy, before the Commonwealth of Pennsylvania Environmental Hearing Board, Docket No. 2011-167-R.
- (jjj) Expert Report (October 2012), Supplemental Expert Report (January 2013), and Affidavit (June 2013) in the matter of various Environmental Petitioners v. North Carolina

DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

- (kkk) Pre-filed Testimony (October 2012) on behalf of No-Sag in the matter of the North Springfield Sustainable Energy Project before the State of Vermont, Public Service Board.
- (III) Pre-filed Testimony (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.
- (mmm) Expert Report (February 2013) on behalf of Petitioners in the matter of Credence Crematory, Cause No. 12-A-J-4538 before the Indiana Office of Environmental Adjudication.
- (nnn) Expert Report (April 2013), Rebuttal report (July 2013), and Declarations (October 2013, November 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).
- (000) Declaration (April 2013) on behalf of Petitioners in the matter of Sierra Club, et al., (Petitioners) v Environmental Protection Agency et al. (Respondents), Case No., 13-1112, (Court of Appeals, District of Columbia Circuit).
- (ppp) Expert Report (May 2013) and Rebuttal Expert Report (July 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. *Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC*, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).
- (qqq) Declaration (August 2013) on behalf of A. J. Acosta Company, Inc., in the matter of A. J. Acosta Company, Inc., v. County of San Bernardino, Case No. CIVSS803651.
- (rrr) Comments (October 2013) on behalf of the Washington Environmental Council and the Sierra Club in the matter of the Washington State Oil Refinery RACT (for Greenhouse Gases), submitted to the Washington State Department of Ecology, the Northwest Clean Air Agency, and the Puget Sound Clean Air Agency.
- (sss) Statement (November 2013) on behalf of various Environmental Organizations in the matter of the Boswell Energy Center (BEC) Unit 4 Environmental Retrofit Project, to the Minnesota Public Utilities Commission, Docket No. E-015/M-12-920.
- (ttt) Expert Report (December 2013) on behalf of the United States in United States of America v. Ameren Missouri, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).

- (uuu) Expert Testimony (December 2013) on behalf of the Sierra Club in the matter of Public Service Company of New Hampshire Merrimack Station Scrubber Project and Cost Recovery, Docket No. DE 11-250, to the State of New Hampshire Public Utilities Commission.
- (vvv) Expert Report (January 2014) on behalf of Baja, Inc., in *Baja, Inc., v. Automotive Testing and Development Services, Inc. et. al*, Civil Action No. 8:13-CV-02057-GRA (District of South Carolina, Anderson/Greenwood Division).
- (www) Declaration (March 2014) on behalf of the Center for International Environmental Law, Chesapeake Climate Action Network, Friends of the Earth, Pacific Environment, and the Sierra Club (Plaintiffs) in the matter of *Plaintiffs v. the Export-Import Bank (Ex-Im Bank) of the United States*, Civil Action No. 13-1820 RC (District Court for the District of Columbia).
- (xxx) Declaration (April 2014) on behalf of Respondent-Intervenors in the matter of Mexichem Specialty Resins Inc., et al., (Petitioners) v Environmental Protection Agency et al., Case No., 12-1260 (and Consolidated Case Nos. 12-1263, 12-1265, 12-1266, and 12-1267), (Court of Appeals, District of Columbia Circuit).
- (yyy) Direct Prefiled Testimony (June 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17319 (Michigan Public Service Commission).
- (zzz) Expert Report (June 2014) on behalf of ECM Biofilms in the matter of the US Federal Trade Commission (FTC) v. ECM Biofilms (FTC Docket #9358).
- (aaaa) Direct Prefiled Testimony (August 2014) on behalf of the Michigan Environmental Council and the Sierra Club in the matter of the Application of Consumers Energy Company for Authority to Implement a Power Supply Cost Recovery (PSCR) Plan in its Rate Schedules for 2014 Metered Jurisdictional Sales of Electricity, Case No. U-17317 (Michigan Public Service Commission).
- (bbbb) Declaration (July 2014) on behalf of Public Health Intervenors in the matter of *EME Homer City Generation v. US EPA* (Case No. 11-1302 and consolidated cases) relating to the lifting of the stay entered by the Court on December 30, 2011 (US Court of Appeals for the District of Columbia).
- (cccc) Expert Report (September 2014), Rebuttal Expert Report (December 2014) and Supplemental Expert Report (March 2015) on behalf of Plaintiffs in the matter of Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants), Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).
- (ddd) Expert Report (November 2014) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New

York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).

- (eeee) Pre-filed Direct Testimony (March 2015) and Rebuttal Testimony (August 2015) on behalf of Friends of the Columbia Gorge in the matter of the Application for a Site Certificate for the Troutdale Energy Center before the Oregon Energy Facility Siting Council.
- (ffff) Expert Report (March 2015) on behalf of Plaintiffs in the matter of *Conservation Law Foundation v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).
- (gggg) Direct Prefiled Testimony (May 2015) on behalf of the Michigan Environmental Council, the Natural Resources Defense Council, and the Sierra Club in the matter of the Application of DTE Electric Company for Authority to Increase its Rates, Amend its Rate Schedules and Rules Governing the Distribution and Supply of Electric Energy and for Miscellaneous Accounting Authority, Case No. U-17767 (Michigan Public Service Commission).
- (hhhh) Expert Report (July 2015) and Rebuttal Expert Report (July 2015) on behalf of Plaintiffs in the matter of Northwest Environmental Defense Center et. al., v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants), Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).
- (iiii) Declaration (August 2015, Docket No. 1570376) in support of "Opposition of Respondent-Intervenors American Lung Association, et. al., to Tri-State Generation's Emergency Motion;" Declaration (September 2015, Docket No. 1574820) in support of "Joint Motion of the state, Local Government, and Public Health Respondent-Intervenors for Remand Without Vacatur," *White Stallion Energy Center, LLC v. US EPA*, Case No. 12-1100 (US Court of Appeals for the District of Columbia).
- (jjjj) Expert Report (November 2015) on behalf of Appellants in the matter of *Sierra Club, et al. v. Craig W. Butler, Director of Ohio Environmental Protection Agency ey al.,* ERAC Case No. 14-256814.

3. Occasions where Dr. Sahu has provided oral testimony <u>in depositions, at trial or in</u> <u>similar proceedings</u> include the following:

- (kkkk) Deposition on behalf of Rocky Mountain Steel Mills, Inc. located in Pueblo, Colorado dealing with the manufacture of steel in mini-mills including methods of air pollution control and BACT in steel mini-mills and opacity issues at this steel mini-mill.
- (llll) Trial Testimony (February 2002) on behalf of Rocky Mountain Steel Mills, Inc. in Denver District Court.
- (mmm) Trial Testimony (February 2003) on behalf of the United States in the Ohio Edison NSR Cases, United States, et al. v. Ohio Edison Co., et al., C2-99-1181 (Southern District of Ohio).

- (nnnn) Trial Testimony (June 2003) on behalf of the United States in the Illinois Power NSR Case, United States v. Illinois Power Co., et al., 99-833-MJR (Southern District of Illinois).
- (0000) Deposition (10/20/2005) on behalf of the United States in connection with the Cinergy NSR Case. United States, et al. v. Cinergy Corp., et al., IP 99-1693-C-M/S (Southern District of Indiana).
- (pppp) Oral Testimony (August 2006) on behalf of the Appalachian Center for the Economy and the Environment re. the Western Greenbrier plant, WV before the West Virginia DEP.
- (qqqq) Oral Testimony (May 2007) on behalf of various Montana petitioners (Citizens Awareness Network (CAN), Women's Voices for the Earth (WVE) and the Clark Fork Coalition (CFC)) re. the Thompson River Cogeneration plant before the Montana Board of Environmental Review.
- (rrrr) Oral Testimony (October 2007) on behalf of the Sierra Club re. the Sevier Power Plant before the Utah Air Quality Board.
- (ssss) Oral Testimony (August 2008) on behalf of the Sierra Club and Clean Water re. Big Stone Unit II before the South Dakota Board of Minerals and the Environment.
- (tttt) Oral Testimony (February 2009) on behalf of the Sierra Club and the Southern Environmental Law Center re. Santee Cooper Pee Dee units before the South Carolina Board of Health and Environmental Control.
- (uuuu) Oral Testimony (February 2009) on behalf of the Sierra Club and the Environmental Integrity Project re. NRG Limestone Unit 3 before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.
- (vvvv) Deposition (July 2009) on behalf of MTD Products, Inc., in the matter of *Alice Holmes and Vernon Holmes v. Home Depot USA, Inc., et al.*
- (www) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Coleto Creek coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
- (xxxx) Deposition (October 2009) on behalf of Environmental Defense, in the matter of permit challenges to the proposed Las Brisas coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
- (yyyy) Deposition (October 2009) on behalf of the Sierra Club, in the matter of challenges to the proposed Medicine Bow Fuel and Power IGL plant in Cheyenne, Wyoming.

- (zzzz) Deposition (October 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed Tenaska coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH). (April 2010).
- (aaaaa) Oral Testimony (November 2009) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.
- (bbbbb) Deposition (December 2009) on behalf of Environmental Defense and others, in the matter of challenges to the proposed White Stallion Energy Center coal fired power plant project at the Texas State Office of Administrative Hearings (SOAH).
- (ccccc) Oral Testimony (February 2010) on behalf of the Environmental Defense Fund re. the White Stallion Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.
- (dddd) Deposition (June 2010) on behalf of the United States in connection with the Alabama Power Company NSR Case. United States v. Alabama Power Company, CV-01-HS-152-S (Northern District of Alabama, Southern Division).
- (eeeee) Trial Testimony (September 2010) on behalf of Commonwealth of Pennsylvania Dept. of Environmental Protection, State of Connecticut, State of New York, State of Maryland, and State of New Jersey (Plaintiffs) in connection with the Allegheny Energy NSR Case in US District Court in the Western District of Pennsylvania. *Plaintiffs v. Allegheny Energy Inc., et al.,* 2:05cv0885 (Western District of Pennsylvania).
- (fffff) Oral Direct and Rebuttal Testimony (September 2010) on behalf of Fall-Line Alliance for a Clean Environment and others in the matter of the PSD Air Permit for Plant Washington issued by Georgia DNR at the Office of State Administrative Hearing, State of Georgia (OSAH-BNR-AQ-1031707-98-WALKER).
- (ggggg) Oral Testimony (September 2010) on behalf of the State of New Mexico Environment Department in the matter of Proposed Regulation 20.2.350 NMAC – *Greenhouse Gas Cap and Trade Provisions,* No. EIB 10-04 (R), to the State of New Mexico, Environmental Improvement Board.
- (hhhhh) Oral Testimony (October 2010) on behalf of the Environmental Defense Fund re. the Las Brisas Energy Center before the Texas State Office of Administrative Hearings (SOAH) Administrative Law Judges.
- (iiiii) Oral Testimony (November 2010) regarding BART for PSCo Hayden, CSU Martin Drake units before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.

- (jjjjj) Oral Testimony (December 2010) regarding BART for TriState Craig Units, CSU Nixon Unit, and PRPA Rawhide Unit) before the Colorado Air Quality Commission on behalf of the Coalition of Environmental Organizations.
- (kkkkk) Deposition (December 2010) on behalf of the United States in connection with the Louisiana Generating NSR Case. United States v. Louisiana Generating, LLC, 09-CV100-RET-CN (Middle District of Louisiana).
- (llll) Deposition (February 2011 and January 2012) on behalf of Wild Earth Guardians in the matter of opacity exceedances and monitor downtime at the Public Service Company of Colorado (Xcel)'s Cherokee power plant. No. 09-cv-1862 (D. Colo.).
- (mmmm) Oral Testimony (February 2011) to the Georgia Office of State Administrative Hearings (OSAH) in the matter of Minor Source HAPs status for the proposed Longleaf Energy Associates power plant (OSAH-BNR-AQ-1115157-60-HOWELLS) on behalf of the Friends of the Chattahoochee and the Sierra Club).
- (nnnn) Deposition (August 2011) on behalf of the United States in United States of America v. Cemex, Inc., Civil Action No. 09-cv-00019-MSK-MEH (District of Colorado).
- (00000) Deposition (July 2011) and Oral Testimony at Hearing (February 2012) on behalf of the Plaintiffs MYTAPN in the matter of Microsoft-Yes, Toxic Air Pollution-No (MYTAPN) v. State of Washington, Department of Ecology and Microsoft Corporation Columbia Data Center to the Pollution Control Hearings Board, State of Washington, Matter No. PCHB No. 10-162.
- (pppp) Oral Testimony at Hearing (March 2012) on behalf of the United States in connection with the Louisiana Generating NSR Case. *United States v. Louisiana Generating, LLC,* 09-CV100-RET-CN (Middle District of Louisiana).
- (qqqqq) Oral Testimony at Hearing (April 2012) on behalf of the New Hampshire Sierra Club at the State of New Hampshire Public Utilities Commission, Docket No. 10-261 – the 2010 Least Cost Integrated Resource Plan (LCIRP) submitted by the Public Service Company of New Hampshire (re. Merrimack Station Units 1 and 2).
- (rrrr) Oral Testimony at Hearing (November 2012) on behalf of Clean Wisconsin in the matter of Application of Wisconsin Public Service Corporation for Authority to Construct and Place in Operation a New Multi-Pollutant Control Technology System (ReACT) for Unit 3 of the Weston Generating Station, before the Public Service Commission of Wisconsin, Docket No. 6690-CE-197.
- (sssss) Deposition (March 2013) in the matter of various Environmental Petitioners v. North Carolina DENR/DAQ and Carolinas Cement Company, before the Office of Administrative Hearings, State of North Carolina.

- (tttt) Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).
- (uuuu) Deposition (August 2013) on behalf of the Sierra Club in connection with the Luminant Martin Lake Case. Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC, Civil Action No. 5:10-cv-0156-MHS-CMC (Eastern District of Texas, Texarkana Division).
- (vvvvv) Deposition (February 2014) on behalf of the United States in United States of America v. Ameren Missouri, Civil Action No. 4:11-cv-00077-RWS (Eastern District of Missouri, Eastern Division).
- (wwww) Trial Testimony (February 2014) in the matter of *Environment Texas Citizen Lobby, Inc and Sierra Club v. ExxonMobil Corporation et al.*, Civil Action No. 4:10-cv-4969 (Southern District of Texas, Houston Division).
- (xxxx) Trial Testimony (February 2014) on behalf of the Sierra Club in connection with the Luminant Big Brown Case. Sierra Club v. Energy Future Holdings Corporation and Luminant Generation Company LLC, Civil Action No. 6:12-cv-00108-WSS (Western District of Texas, Waco Division).
- (yyyy) Deposition (June 2014) and Trial (August 2014) on behalf of ECM Biofilms in the matter of the US Federal Trade Commission (FTC) v. ECM Biofilms (FTC Docket #9358).
- (zzzz) Deposition (February 2015) on behalf of Plaintiffs in the matter of Sierra Club and Montana Environmental Information Center (Plaintiffs) v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and Pacificorp (Defendants), Civil Action No. CV 13-32-BLG-DLC-JCL (US District Court for the District of Montana, Billings Division).
- (aaaaaa) Oral Testimony at Hearing (April 2015) on behalf of Niagara County, the Town of Lewiston, and the Villages of Lewiston and Youngstown in the matter of CWM Chemical Services, LLC New York State Department of Environmental Conservation (NYSDEC) Permit Application Nos.: 9-2934-00022/00225, 9-2934-00022/00231, 9-2934-00022/00232, and 9-2934-00022/00249 (pending).
- (bbbbbb) Deposition (August 2015) on behalf of Plaintiff in the matter of *Conservation Law Foundation (Plaintiff) v. Broadrock Gas Services LLC, Rhode Island LFG GENCO LLC, and Rhode Island Resource Recovery Corporation (Defendants)*, Civil Action No. 1:13-cv-00777-M-PAS (US District Court for the District of Rhode Island).
- (ccccc) Testimony at Hearing (August 2015) on behalf of the Sierra Club in the matter of *Amendments to 35 Illinois Administrative Code Parts 214, 217, and 225* before the Illinois Pollution Control Board, R15-21.

- (ddddd) Deposition (May 2015) on behalf of Plaintiffs in the matter of Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants), Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).
- (eeeeee) Trial Testimony (October 2015) on behalf of Plaintiffs in the matter of Northwest Environmental Defense Center et. al., (Plaintiffs) v. Cascade Kelly Holdings LLC, d/b/a Columbia Pacific Bio-Refinery, and Global Partners LP (Defendants), Civil Action No. 3:14-cv-01059-SI (US District Court for the District of Oregon, Portland Division).

II. Outside Persons Who Wish to Address the Commission at Internal Affairs

OUTSIDE PERSONS WHO WISH TO ADDRESS THE COMMISSION AT

INTERNAL AFFAIRS November 29, 2016

<u>Speaker</u>

Representing

Item #

The Honorable Mignon Clyburn

Federal Communications Commission

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III.Supplemental Materials for Internal Affairs

<u>Note</u>: The records reflect that there were no supplemental materials provided to the Commission during this Internal Affairs meeting.

IV. Transcript

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

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4	PROCEEDINGS:	INTERNAL AFFAIRS
5	COMMISSIONERS PARTICIPATING:	CHAIRMAN JULIE BROWN
6		COMMISSIONER LISA POLAK EDGAR COMMISSIONER ART GRAHAM
7		COMMISSIONER RONALD BRISÉ COMMISSIONER JIMMY PATRONIS
8	DATE:	Tuesday, November 29, 2016
9	m T) (T)	c
10	TIME:	Commenced at 10:29 a.m. Concluded at 11:57 a.m.
11	PLACE:	Gerald L. Gunter Building
12		2540 Shumard Oak Boulevard Tallahassee, Florida
13		
14	REPORTED BY:	Official FPSC Reporter
15		(000) 410 0704
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	FLORIDA	PUBLIC SERVICE COMMISSION

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PROCEEDINGS

CHAIRMAN BROWN: All right. Good morning still. We are so excited and delighted to have Commissioner Clyburn here. This is our official Internal Affairs meeting. We're going to begin with Commissioner Clyburn, but first I'd like to ask our Commissioner Ron Brisé to introduce her and give a little background for those of you watching and in the audience.

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Commissioner Brisé.

COMMISSIONER BRISÉ: Thank you, Madam Chair. And, Commissioner Clyburn, thank you for coming today. Sorry that the weather is a little inclement.

COMMISSIONER CLYBURN: That's all right. It's 70 degrees. It's okay.

(Laughter.)

COMMISSIONER BRISÉ: I know it's a lot warmer than D.C., so we certainly appreciate you being here.

And so I do have a script. I'm going to move away from the script, if that's okay with you.

COMMISSIONER CLYBURN: Thank you.

COMMISSIONER BRISÉ: So we know Commissioner Clyburn as a former colleague, as a South Carolina commissioner, and so she has a great understanding of

the work that we do day in, day out and the spread of disciplines that we have to delve deeply into. But now she's specialized. Right? She's a communications specialist. And President Obama recognized that, and he appointed her to the Commission twice, and she served as acting chair of the Commission. And during that time period, she accomplished quite a bit, and hopefully you'll talk a little bit about your accomplishments when you were serving as acting chair.

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So a little bit of background about Commissioner Clyburn. She has a little bit of background in the newspaper business. It's part of her passion. If you listen to her ask questions and interact with her, you'll notice that she's very inquisitive, and I think some of that has to do with that background as well.

She and I serve as colleagues on the Joint Board currently, and she's a very active member of the Joint Board. And as state members, we appreciate the fact that you participate, you're active, and, when possible, you are actually physically there. So we certainly appreciate your participation in that with us. But overall she's a wonderful human being and

COMMISSIONER CLYBURN: And I didn't pay him.

I promise.

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(Laughter.)

COMMISSIONER GRAHAM: I've never heard him say that before about anybody.

COMMISSIONER BRISÉ: A wonderful human being, a kind soul, one who cares about others and is interested in seeing that the interests of those who are underrepresented have their voices heard. So thank you for bringing that to the Commission. And we appreciate the work that you've done for your state and for our nation.

COMMISSIONER CLYBURN: Thank you so much.

CHAIRMAN BROWN: Thank you, Commissioner

Brisé.

And, Commissioner Clyburn, we're going to turn it over. We want to make this as laid back and informal as you like.

COMMISSIONER CLYBURN: Thank you.

CHAIRMAN BROWN: So please go ahead. And I understand that you have a few comments, and then we'll get into some questions.

COMMISSIONER CLYBURN: And feel free to interrupt at any time if it gets too lengthy, but do it in that southern way that we know best.

CHAIRMAN BROWN: Yeah, right.

(Laughter.)

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COMMISSIONER CLYBURN: Again, good morning, everyone. Chairwoman Brown, thank you. Commissioner Brisé, other Commissioners, and the staff of the Florida Public Service Commission, I thank you for inviting me to take part in today's meeting.

On April 3rd, 1973, Marty Cooper held up to his ear a device many refer to today as a brick as he placed what would be the first ever mobile phone call. This pivotal moment in history shaped and redefined our entire communications landscape. Now given that backdrop, I trust you will forgive me this morning if I come across as overly reflective, but pause with me for a moment and consider just how many technological barriers have been broken and the tremendous amount of innovation that has led to this era of smartphones, smart homes, and smart gigabit speed cities. Because at the forefront in advancing access to robust, affordable communication services is the Federal Communications Commission.

Over the years, consumers have come to expect, when they pick up their telephone, that the call will be completed; however, the basic infrastructure delivering that call is changing. Copper lines are being replaced with optical fiber. Wired phones, particularly those in

the home, they're being eclipsed by wireless technology. Like millions of Americans, I am guilty. I, too, have made the switch from a legacy landline to Voice over the Internet Protocol -- sorry to some of the colleagues back there -- or a wireless connection as my primary means of communication. But as technology evolves, spurring new and more exciting opportunities, it is important now, as it was when Marty Cooper made that first call, that we never lose sight that whenever or whatever that device or system, reliable calls, texts, and browsing abilities over both fixed and mobile connections, they should continue.

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As regulators, we will always encourage innovation and market growth, but that is not our only job. We are charged with protecting the consumer interest, which brings with it a multitude of challenges and an endless array of questions. How do we determine what kind of consumer protections are necessary with technologies that have yet to be fully deployed? How can the FCC work with industry to ensure these technological transitions are successful? And how do we collectively craft policy decisions that will stand the test of time?

Allow me to spend the bulk of my time highlighting a few of the initiatives the Commission is

undertaking to address these very real and extremely important concerns.

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Let me start by saying what I hope is the most obvious. It is the FCC's responsibility to ensure that communities across the country are provided with safe, affordable, and reliable means of communications. This is not a Mignon Clyburn thing. It is a clear statutory mandate that explains why we have been so fixated at the FCC on connecting communities with advanced communication services.

By the FCC's own account, 34 million Americans lack access to broadband defined as download speeds of at least 25 megabits per second. This equates to about 10 percent of our fellow citizens, many of whom are stuck on the wrong side of the digital divide, with limited options for immediate relief. This is why I personally believe local governments that want to bring broadband connectivity to their communities, particularly when the private sector has failed to do so, should have that right. However, lack of affordability remains one of the largest barriers to connected communities. And in rural areas, according to the U.S. Department of Agriculture, as of 2013, 18 percent of consumers live in poverty. In some areas of the country, including our precious south, that

number exceeds 20 percent. Sadly, these areas often have worse broadband experiences when compared to their more urban and effluent neighbors, which is why we must ensure that providers are able to deploy and upgrade their infrastructure at the lowest cost and the quickest pace.

There are several ways to help remedy this. Establishing minimum service standards which would lead to better levels of service for Lifeline recipients is one way. Lifeline, as you know, is the only federal benefit program that I am aware where the provider determines the consumer's eligibility. That must change.

We must also encourage broader participation by eliminating unnecessary barriers that discourage provider participation. We need public/private partnerships and coordinated outreach efforts because the lack of a centralized effort is leaving far too many who qualify behind.

In addition to addressing these critical broadband issues, the FCC has been actively pushing for more opportunities to facilitate the next generation of fixed and mobile services. Technology transitions have been a continuous concept facing the FCC for many years. Just before I started at the Commission in the summer of

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2009, which seems like only yesterday, but the wear and tear -- (laughter) -- the country made the switch from analog to digital TV.

Today we face a new wave of technology transitions. The Commission has been examining the effect that such a transition has on consumers when communications providers switch from copper to fiber and from wireline to wireless. It is absolutely crucial that regardless of the transition or switch that is taking place, consumer protections remain robust.

During my six-month Connecting Communities Tour across this incredible nation, I had the opportunity to observe just how important it is that modern communications technologies are reliable, adequate substitutes for services poised -- that are poised, I should say, to be discontinued. Such protections includes -- include consistently reliable 911 access and fast, first-rate, and affordable service regardless of where one lives.

The FCC has given VoIP providers numerous resources and has built the framework for providers looking to test IP transitions. We have adopted efficient requirements to include that there are more affordable and adequate replacements for when providers discontinue a video service.

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And speaking of adequate replacements, let's talk about unlocking the 5G revolution. There's a lot of buzz around 5G, and I share in this excitement. This past July, the Commission voted unanimously, unanimously to open a sizable amount of spectrum for next-generation high-speed 5G wireless applications and networks. However, the explosive levels of consumer demand necessitate that we start looking for more spectrum in higher-up frequencies.

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In moving towards 5G, I believe that the FCC must look to make sure that four things happen: We must make available spectrum in low-, mid-, and high-frequency bands with flexible rules; we must continue to remove barriers to infrastructure siting; quickly approve requests to test new technologies in these bands; and consider cyber issues at the beginning of the process.

Why are these four steps so crucial? Mobile data traffic has increased by 4,000-fold over the past ten years and almost 400 million-fold over the past 15 years. The need for mobile data growth is greater than ever before as American consumers become more and more reliant on smartphones, tablets, and other wireless devices.

We must, however, ensure that the benefits of

high-speed wireless broadband, that this reaches all communities, including the more than 50,000 Americans, believe it or not, who still rely on 2G service.

The FCC has worked hard towards crafting a flexible spectrum policy that meets this wireless broadband demand. Industry engineers have uncovered ways to use short wavelengths -- ways to use short wavelengths to construct dynamic beamforming antennas -please don't ask me about this -- that will support high-capacity networks in a device the size of a handset. And I have no doubt that the FCC will continue to work with our federal partners to implement creative spectrum sharing regimes. But 5G connectivity is largely reliant on the availability of more spectrum, which is why I support passage of the Mobile Now Act cosponsored by your own senator, Bill Nelson, which directs the FCC and NTIA to free up spectrum that is essential to the deployment of 5G.

Additionally, four years ago Congress authorized what is known as the Broadcast Incentive Option, which created a mechanism for television broadcasters to voluntarily relinquish their spectrum in exchange for proceeds from auctioning the airways to wireless companies. The first phase of Stage 2 concluded on October 19th, and we're now in Stage 3 of

that auction with a clearing target of 108 megahertz. This is an important step in providing much needed low band spectrum that the agency -- the industry is clammering (phonetic) for, the agency wants, and consumers need for reliable wireless service.

Earlier this year we established new rules for the 3.5 gigahertz band. The licensing model that the FCC created will enable access to at least 80 megahertz of spectrum and even 150 megahertz in some places without going to auction. These new rules will make additional spectrum available for flexible wireless broadband use and will improve broadband access and performance for consumers.

Also, these rules will likely expand wireless broadband deployment in industrial settings, paving the way for, among other things, advanced manufacturing and healthcare capabilities. This is a great opportunity for all users to gain access to a substantial amount of spectrum to support innovation and economic growth.

Equally important as we move to the next generation of wireless is collaboration between industry and state and local governments when it comes to infrastructure siting. Earlier this year the Commission reached an agreement with the National Conference of State Historic Preservation Office and the Advisory

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Council on Historic Preservation on a Distributed Antenna System and small cell amendment to the collocation amendment agreement. What this means is the amendments will enable swift and responsible deployment of wireless broadband services to support next-generation wireless service offerings while maintaining the vital role that states and tribal nations play in reviewing projects with potentially significant environmental effects. The Commission's work here recognizes the interests of local communities to preserve the integrity of their neighbors while maximizing the potential to meet rising connectivity needs. This is an important factor when considering build out and deployment plans. Approving applications to site antennas and other infrastructure are no doubt difficult policy challenges for you at the local governmental level, but I believe that we can successfully meet these challenges if all stakeholders collaborate.

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Carriers are tired of hearing me say this, but I will say it again, that we must absolutely engage with local communities, find out their basic and specific needs, and show just how, when we're talking about 5G, that it can help address their specific needs. By working together, we can assure that all Americans, no

matter where they live, can benefit from the promise of 5G.

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And as part of ensuring consumers enjoy all that 5G has to offer, they must be able to take full advantage of online applications and services without fear of throttling or blocking by their broadband provider.

Last year, as you know, the Commission undertook a landmark step to protect an open internet. That order was supported by millions of Americans but opposed by some service providers. They sued to overturn what I believe are common sense consumer protections.

Earlier this year the D.C. circuit handed us a resounding victory at the FCC, upholding our order in its entirety. And I am confident that despite future legal challenges, we will continue to prevail. That order was heralded by some as the death knell for future investment and innovation in the internet, but time continues to disprove that position. Our careful calibration of the regulatory framework for broadband avoided using heavy-handed regulation for a more flexible approach like that applied to mobile wireless two decades ago. Title II light, transparency, a few bright-line rules, and a general conduct standard

combined to provide certainty and flexibility for consumers and providers alike.

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We have seen this success play out in the marketplace with providers purchasing spectrum at record high prices, pouring money into the next generation of communications technologies, and increasing the coffers of our government, and that's a good thing.

Despite these positive results, some are suggesting we roll back these consumer protections, but it shouldn't surprise you that I disagree. I usually play things close to the vest, but I will continue to openly oppose actions that will roll back what I believe are sensible protections for broadband consumers. And while our open internet order ensured that consumers have unfettered access to the internet, we must also secure our networks.

The FCC has a fundamental responsibility to promote security and reliability in communications networks, and this has become even more important as we move to this all IP environment.

Privacy is a priority for consumers, which makes it a priority of ours. 91 percent of Americans believe consumers have lost control over how their personal information is collected and used by companies. However, considering the continual cyber attacks,

massive data breaches, and companies collecting and selling consumer information to government agencies, this is, unfortunately, not surprising.

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In October of this year, the FCC took a substantial step in remedying this unfortunate abuse of consumer privacy by adopting the broadband privacy order. This order, I am proud to say, implements strong privacy protections with substantial consumer flexibility. Importantly, only consumers who consent to the use or sharing of their information will have the opportunity to receive more targeted advertising, new products, or other innovative offerings made possible by big data. This order cracks down opaque privacy provisions, including tougher safeguards for consumers. And I am especially proud of the wholesome protective coverage this order provides. It takes into account people with disabilities and ensures that protected classes under our national civil rights laws are taken into account. I am confident in the security that these rules will provide for consumers and hopeful that this order will enable choice and control that consumers are demanding.

As our valued state partner, I am once again happy to be here, and I'm grateful for the opportunity to speak and take questions today. If you have any, I

will be here and willing to answer them. Again, thank you very much, and thank you, Chairwoman.

CHAIRMAN BROWN: Thank you. I'm going to give you applause here. That was excellent.

(Applause.)

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Thank you. Commissioner Clyburn, you are just a fantastic, super woman, great leader on these issues, and just thank you for the enlightenment. I want to thank our staff, Cayce Hinton and Mark Long, for securing you here today. It is just -- it's a treat for all of us. And I'm sure my fellow Commissioners and possibly staff have some questions that you raised, but I'll start with our resident telecom expert, Commissioner Brisé.

COMMISSIONER CLYBURN: Okay. Oh, my goodness. COMMISSIONER BRISÉ: A lot of pressure. COMMISSIONER CLYBURN: On me.

CHAIRMAN BROWN: He is our expert on telecom issues.

COMMISSIONER BRISÉ: So thank you for being here. I'm going to ask you one question about Connect2Health and the task force and how that's going. I know that you visited Miami --

COMMISSIONER CLYBURN: Yes.

COMMISSIONER BRISÉ: -- and Jacksonville as

part of that. If you can give us an update as to how that's going, where we are with that, and what are some

COMMISSIONER CLYBURN: So we're into year two of an initiative that I feel personally wedded to. We came -- when we came to Miami and Central Florida -- in Jacksonville visiting Mayo Clinic and speaking with seniors about some of their needs, it was so obvious to me the power of connectivity and the power of telehealth and telemedicine. But what is still troubling and should concern all of us is that the basic tools needed to facilitate and ensure that this is optimal is absent in too many communities. Affordability remains a problem, which is why I have been fixated on reforming Lifeline and providing other means in our universal service arsenal to ensure that connectivity is there. But we must have this -- we must double down on state and local public/private partnerships to make sure that these realities are seen.

I always use this example when I talk about the task force. A visit that we made to one of our other southern neighbors with a small pilot program in a very rural city, rural town in, I'll say it, in Mississippi, as we say in the south, they took a small group of high presenting diabetics, provided them with

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of the results.

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connectivity, a computer that -- he's heard this story a hundred times, so I apologize.

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COMMISSIONER PATRONIS: I haven't heard it. You've got my attention.

CHAIRMAN BROWN: Not us, not us.

COMMISSIONER CLYBURN: But, yeah, I apologize. And what they found within a year is that that group, that subset that grew from 100 to 200, that there were no hospitalizations over that year; one patient in that study group the previous year had been in the hospital six times; that they saved \$339,000 to their state Medicaid fund, again, a very small subset; that they saved 10,000 miles, road miles because of avoided travel; and that you had an 80-something-year-old grandmother almost being the leading cheerleader. The one person that you think would have -- she was fearful of connectivity. Now she's the one helping to make sure that more people are compliant. I cannot tell you -- I use that example over and over again, the power of connectivity and what it can do to better enable people to take more control over their health and wellness.

So the Connect2Health Task Force is attempting to -- community by community, agency by agency, making sure that the FCC as a partner is out of the way. It's helping you smooth over the regulatory landscape to make

sure all of this is possible.

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And one other thing since we met last time, we launched a broadband mapping tool. And if you go on our website, you will be able to -- it's open source, and you will be able to put in whatever variables you like. Here's an example. Say you go to, you know, this particular area and want to see the number of, say, veterans because a lot of, you know -- a lot of seniors in a certain subgroup, you can click, put those variables in, you can upload your own variables, and look at what their broadband connectivity experiences are. And this could be a positive for healthcare professionals as well as entrepreneurs saying what is needed, what is missing, and how we can build on, you know, these -- you know, what is -- what we foresee, you know, over the horizon.

And so the task force, it is interesting but it's because -- in a way it's hard for me to put it into words because I don't think it will never, ever outgrow its usefulness. And I don't know -- you know how people want to say here's the deliverable? I don't know where that ends. It will end when we are all comfortable and more healthy and not using emergency rooms, you know, as our primary, you know, first line of defense when it comes to health and wellness. But we all -- as we live

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	longer (knocking on table) is this real wood?		
2	CHAIRMAN BROWN: It's real wood. It is.		
3	COMMISSIONER CLYBURN: Okay. As we live		
4	longer and, you know, want to be more healthy and more		
5	in control, I believe this task forcing and connectivity		
6	and ensuring that we have a partnership when it comes to		
7	connectivity will really pay dividends, save money.		
8	If you want to just speak in business terms,		
9	if you don't if the squishiness of that is not your		
10	thing, real money, real time that's being saved and		
11	realizing realized and more efficiency, and that's		
12	what we're hoping that this task force will help to		
13	further facilitate.		
14	COMMISSIONER BRISÉ: Thank you.		
15	CHAIRMAN BROWN: Thank you.		
16	Commissioner Patronis.		
17	COMMISSIONER PATRONIS: Thank you.		
18	And thanks for your presentation. It's		
19	awesome.		
20	COMMISSIONER CLYBURN: Thank you.		
21	COMMISSIONER PATRONIS: Poor Ron. I'm a nerd		
22	and I'm constantly peppering him with questions when he		
23	comes in because every once in a while I feel like I've		
24	got an opportunity to really get a lot of just you		
25	can ask him. I ask him all types of off-the-wall		
20	can ask mim, i ask mim all cypes of old the wall		

questions around wireless, and I'm just intrigued by it and fascinated.

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And you touched on a couple of things that brought up a question that I've got. I've noticed over the past year you've seen where certain carriers have been able to embrace Wi-Fi calling.

COMMISSIONER CLYBURN: Okay.

COMMISSIONER PATRONIS: Where does -- and it seems like there's been some bumps in how that has been allowed. Is -- why is it either not fully implemented or why -- is it -- it seems likes sometimes the carriers don't play well with each other when it comes to allowing that to be part of their portfolio. I'm kind of --

COMMISSIONER CLYBURN: So I'll see if I can answer your question. When you talk about the power of, you know, what Wi-Fi has done for this nation and what it has -- when you talk about avoided costs and actual benefits, when you talk about offloading and the like, I mean, Wi-Fi has been this incredible tool that allows more affordability, more ubiquitous, and saving money. Because when you talk about, you know, offloading that traffic instead of building more towers and the like, it has really been a positive benefit. When you talk about some of the bumps in the road, I mean, what fun would it
be if there weren't bumps?

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COMMISSIONER PATRONIS: Yeah, yeah. COMMISSIONER CLYBURN: I mean, you know, respectfully, and I'm not being flippant, it allows for us to, you know, recognize and, you know, to be more

vigilant as regulators to see if we need to -- if there -- if we need to provide more guidance. Wink, wink.

COMMISSIONER PATRONIS: Uh-huh. Yeah, yeah, yeah.

COMMISSIONER CLYBURN: And it also, you know, forces, you know, hopefully forces the competing entities to know that a mutually -- that standards in a mutual platform saves money, you know, for all.

So, you know, I hear what you're saying, probably not as directly answering your question, you know, around the contours. But the benefit of, you know, of Wi-Fi, you know, in omnibus, it speaks for itself. And I often jokingly say, not trying to be sort of, you know, confrontational, is that these are the types of things that honestly, from a regulatory standpoint, there were many who did not see the benefit of moving in this direction. But the FCC luckily, you know, fortunately for all of us, along with state engagement, you know, from your colleagues who might

have been here a couple of years longer than you, but you, you know, of course, are, you know, active at this point, that, you know, we see the benefit. And we would just continue to be, you know, the cops on the beat and referees to ensure that this great amount of innovation and investment and -- that the playing nice has, you know, positive economic benefits.

COMMISSIONER PATRONIS: Follow-up?

CHAIRMAN BROWN: Yes.

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COMMISSIONER PATRONIS: So do you find yourself at times -- I think you kind of hit the nail on the head -- playing referee amongst the children?

COMMISSIONER CLYBURN: Absolutely.

COMMISSIONER PATRONIS: And getting them to acknowledge deficiencies or lack of service that they maybe should consider?

COMMISSIONER CLYBURN: So let me give you a concrete example, and please watch the time. I'm from the south like you. I'm a PK, I say, twice removed. I'm a politician's kid, and he was a preacher's kid. So we just, you know --

CHAIRMAN BROWN: I could listen to you all day.

COMMISSIONER CLYBURN: You are very kind. CHAIRMAN BROWN: But we've got a couple of

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other reports, but all day.

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COMMISSIONER CLYBURN: So I'm going to give you an example when I had the fortunate, you know, benefit of being interim chair. We had this issue that had been on -- that has been a challenge called the lack of interoperability in the lower 700 megahertz space. Okay. We can talk about that later offline. But what that meant, especially for smaller providers in rural communities who bought this spectrum, they were landlocked because the standards body changed, you know, some protocols, leaving them unable to build out and unable to get devices that worked on their network. So they couldn't get the latest in smart, you know, smartphones. And so the big carriers were doing it exceptionally well. The smaller carriers honestly were one or two generations behind and losing customers like you would not believe. And so we could not get to a point where the big guys and the small guys could agree, so -- I'm trying to put this in a way so I can go back home.

(Laughter.)

COMMISSIONER PATRONIS: I get it. I get it. COMMISSIONER CLYBURN: So what we did was we had a room not much bigger than this, had some windows for a little bit of ambience, so you can tell the

architects you need windows, and what we do is we have the carriers in the room and their supporters and we talked and we talked and we talked, and within a couple of weeks of that we had a voluntary agreement which short-circuited all of the challenges that would have been sure to come.

When we talked -- you talk about, you know, getting devices and build out. We thought things that would be happening in a year happened in six months. And these small carriers, many -- you know, some who serve your state, are now honestly competing not having to worry about their customers having to have a second phone when they come -- you know, leave the area.

COMMISSIONER PATRONIS: Yeah, yeah.

COMMISSIONER CLYBURN: You know, all of these things made possible by a little direct engagement, you know, from -- I am very proud of that, some people might criticize -- but just old-fashioned sitting in a room saying, "How far are we apart?"

And what I found, and not trying to get political, it's hard not to in this environment, what I found in that engagement is what I've been taught and what I hope others will take as we move forward.

There's usually one, two, or three things that are separating us, you know, from nirvana, and I found

that they weren't that far apart. It had been so entrenched because it had been five, six, or seven years before they really talked to each other. They talked at each other but not to each other. And, believe me, those small, little carriers wanted me to put an order, which I'm telling you now they would not have been building at this point, we would still be in court. And so when you can do that as a regulator, honestly, not trying to scare the folks behind us, but, you know, embrace your power to do so because nine times out of ten it pays substantial dividends. I'm very proud of that. It was definitely bipartisan. People are still shaking their your heads and saying, "How you did it?" I said, "I rolled up my sleeves and practiced the lessons I was taught at home, that you talk it out when you have a disagreement."

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And so I don't want to be repetitive. That's the power you have as a regulator, to enable innovation and investment in a short-circuited manner, saving time and money, and getting the consumers the types of products and services they need.

COMMISSIONER PATRONIS: Cool. Thank you. CHAIRMAN BROWN: I have two questions. I have really 50, but two questions. I'm going to limit them to two because I know your time is precious. I think

the other Commissioners may have some. But you talk about the broadband privacy order. It is such a sensitive issue --

COMMISSIONER CLYBURN: It is.

CHAIRMAN BROWN: -- for so many consumers, and the selling of sensitive customer data. And really I want to hear a little bit more from your perspective on how that's actually in reality working out.

COMMISSIONER CLYBURN: So, as you can imagine, not everybody is happy because it was very -- for a number of years the FCC has been acting in a space when it comes to voice services. And now with reclassification and the like, we have updated those rules for voice and expanded it to broadband. Now the exception, as you know, we did not extend this to, you know, those edge providers, you know, the companies that a lot of people say they're based on the West Coast in some of their -- over which the FCC has authority. So that's one thing we did not do.

But what we basically said is that consumers should have choice over how their information is used. And so we -- I simplify things when it comes to this particular item and say you've got an opt-in and an opt-out approach. So in terms of what you can actively do in terms of the kind of control that you have over

the information, if you want to, you can allow your internet service provider to share and use your sensitive information to include your precise geolocation, exactly where you are, your financial information, health information. If you choose to do so, you can. But what we said is that you cannot automatically do that, internet service provider. You cannot automatically share a social security number or web browsing history or app usage history.

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CHAIRMAN BROWN: And that's excellent.

COMMISSIONER CLYBURN: And so, again, but what -- you, as a consumer, can hit that opt-out button. Right now, unless you opt out, they can share your email address. That's not considered sensitive information. They can share what your -- what service tier you have chosen. That's not sensitive information. But the information that most of us would agree that would be sensitive, you know, information, you know, the content of your communications, we said that you have to get permission from the consumer in order to share that information. Again --

CHAIRMAN BROWN: I think that's excellent. I mean, I think -- I commend you all for producing that order.

What are the big issues? What do you think is

the biggest issues that customers, from a customer perspective that you're hearing concerns throughout the nation other than -- I mean, obviously right now you guys have been working on the reform of Lifeline --

COMMISSIONER CLYBURN: Right.

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CHAIRMAN BROWN: -- and other issues. But is there a particular area of interest that you're hearing from customers' complaints?

COMMISSIONER CLYBURN: So robocalls, that's probably the number one complaint. And, you know, this is something that we have been -- so if you were to look at -- you know, that is a big deal with us. And the -if you talk about numbers, in my interactions, inmate calling rates, that's something that I've been, you know, active in in a number of years and could still use some help at the state level. I'm not sure if --

CHAIRMAN BROWN: This state?

COMMISSIONER CLYBURN: We'll talk offline about that. But, you know, those are issues -- when you talk about issues that, particularly that impact millions of people who may or may not have a voice to change their, you know, conditions, you know, those are the couple of things.

To me, it is about -- going back, when I got at the FCC in '09, one of the things -- I had a great

gift other than the appointment. What we were producing at that point that we delivered that next year was the National Broadband Plan. Now that, if you haven't looked at it, it's a little dated now, but, I mean, it's a really incredible template and blueprint for trying to meet policy and national priorities, meaning policies within the regulatory space and what we want for our nation.

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You want, you know, people to be able to, you know, at the -- in a convenient way to be able to search for a job because, you know, most Fortune 500 companies, if you're going to apply for a job, you can only do so online.

CHAIRMAN BROWN: Right.

COMMISSIONER CLYBURN: You know, we talked about the efficiencies that can be realized in healthcare. We talked -- you know, we hinted at some of the disconnects that are in our communities when you're talking about our schools that are not equally funded, that might not have a certain teacher in the classroom that, you know, if they're connected, they could still have learning possibilities. If they want to take them on, you know, they can.

CHAIRMAN BROWN: Right.

COMMISSIONER CLYBURN: Chances are slight that

they have a teacher that -- in their -- but there's classes, there are schools that don't have a Spanish teacher. And so, you know, how do you provide for, you know, these opportunities?

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So we're just little by little looking at the particular ways inside of our portfolio. This is the one time that I like taking a siloed approach to, you know, regulation, that, you know, how can we, you know, build, you know, better, you know, infrastructure physically as well as around the contours from a regulatory, you know, standpoint to encourage partnerships? How can we do that better to serve our individuals?

You hear a lot of talk, if you're inside the Beltway, about process reform. I know you get that too, you know, about what all we can do to make things --

CHAIRMAN BROWN: And at NARUC we've heard that too, which my fellow colleague supported a resolution about that.

COMMISSIONER CLYBURN: Well, you know, we'll talk about that later too. But anyway, you know, that's in, you know, in the eye, you know, the eye of the beholder.

On the open internet side, you know, the president-elect has made certain overtures, and so, you

know, we'll have to -- we're in a wait-and-see mode about that. But under the open internet portfolio, zero rating or sponsored data plans is something you hear a lot about, if you want to go into detail about that.

A couple of things. We're kind of in a sort of stand-down mode at the FCC, as you probably know, in terms of a couple of items that were going to be on the agenda that are still circulated is -- I used to call it special access. I'm trying to get used to the new terminology, BDS, which, you know -- anyway it's called business data services.

CHAIRMAN BROWN: You have so many acronyms.

COMMISSIONER CLYBURN: Yeah, I know. I'm an old school person, so I'm used to set-top boxes. You might have, you know, heard about that. That is still in limbo. The Lifeline reform, as we mentioned, goes into -- the first phase goes into effect December 1. I've talked about the incentive auction, you know, what stage we are with that.

Another thing that's still circulating that I'm really -- that I know you would be interested in in a number of ways is the Mobility Fund, the next phase. We had Mobility Fund Phase 1 in 2011 that -- you know, to the tune of about \$300 million was circulated into

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the system. Forty-plus states, you know, took advantage of that and really providing next-generation capabilities, but the job is not done. So what I'm hoping is that we will -- you know, I've got my wish number.

CHAIRMAN BROWN: Yes.

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COMMISSIONER CLYBURN: But something north of 300 million I hope will be in the next phase of that that will really provide the needed, you know, coverage. Because particularly when you talk about low or moderate income individuals, low income individuals have cut the cord. About 60 or close to 60 percent of them are wireless only households. So we need to make sure that they're not vulnerable, especially in areas where they might have, you know, issues with connectivity.

I mentioned, you know, robocalls, you know, being top and center. And one of the things that might make it -- so let me rephrase before I tell the family secrets. Another, you know, thing that we've been talking about lately that you may hear about soon more is about 911 location accuracy. That is a big issue and a big problem. We are in this beautiful building. If you dial 911, to be honest with you, I cannot say that emergency services can exactly, you know, find you precisely where you are. If you're outside, I'm not

000035 really worried about you. I think they will find you. 1 I'm worried about you -- you know what I mean, you know. 2 3 CHAIRMAN BROWN: We know what you mean. COMMISSIONER CLYBURN: I'm not worried about 4 5 you being found when you dial 911. Inside of buildings, particularly buildings with certain complexities, 6 7 honestly that is a problem. CHAIRMAN BROWN: It is. 8 9 COMMISSIONER CLYBURN: And we took some first steps about a year or so ago, and that -- but still 10 nirvana for us is like just north of 60 percent. We've 11 got a lot of work to do in terms of getting that to be 12 100 percent, and I think that collectively and with 13 14 support from you that we'll get there. CHAIRMAN BROWN: Commissioner Clyburn, you're 15 doing so much and you've done so much during your term, 16 17 and we're very proud of you. 18 Commissioners or staff, any questions that 19 you're dying to ask? COMMISSIONER CLYBURN: Or comments. 20 21 CHAIRMAN BROWN: Or comments. 22 COMMISSIONER CLYBURN: What I can take back 23 I know Braulio has some. I know his look. I've home. 24 known Braulio for a number of years. 25 MR. BAEZ: I'm listening intently.

000036 COMMISSIONER CLYBURN: I know his look. 1 MR. BAEZ: We can talk about that offline. 2 3 I'm taking the message. We can talk about that offline. Thank you, though. 4 5 COMMISSIONER CLYBURN: Okay. CHAIRMAN BROWN: Well, it's just such a 6 7 pleasure, Commissioner. COMMISSIONER CLYBURN: Lisa --8 9 COMMISSIONER EDGAR: I could go and go and go. 10 Okay. I didn't want to interrupt. Braulio and I are probably the only ones in --11 at the table anyway, I don't know about the room, but at 12 13 the table who actually served as state commissioners at 14 the same time that Commissioner Clyburn was serving as a 15 state commissioner from the great state of South Carolina. 16 17 COMMISSIONER CLYBURN: Yes, absolutely. 18 COMMISSIONER EDGAR: And she followed shortly 19 after another SEARUC commissioner, my friend and the former commissioner from the state of Tennessee --20 21 COMMISSIONER CLYBURN: Tennessee, Deborah 22 Tate. 23 COMMISSIONER EDGAR: -- Deborah Tate, who 24 moved from being a state commissioner for the southeast 25 and then served as -- and Braulio worked with her as

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COMMISSIONER CLYBURN: FCC commissioner. Uh-huh.

COMMISSIONER EDGAR: Went to an FCC commissioner from being a SEARUC state. And I, you know, I think it's so important at our federal regulatory agencies to have representation and the voice of people who have worked on behalf of the state.

COMMISSIONER CLYBURN: Right. Absolutely.

COMMISSIONER EDGAR: And the public interest from the perspective of the state view, in addition, of course, to the federal and regional. And, of course, to just throw out, as long as I'm name dropping, you know, at FERC I think it's the same thing.

COMMISSIONER CLYBURN: Yes.

COMMISSIONER EDGAR: We have Commissioner Tony Clark, a dear friend of many of us, and, of course, our friend Commissioner Colette Honorable --

COMMISSIONER CLYBURN: Right.

COMMISSIONER EDGAR: -- who also moved from being a state regulatory official --

COMMISSIONER CLYBURN: Yes.

COMMISSIONER EDGAR: -- to the federal. So I have to ask the most obvious question ever, which is what is, from moving as a state

commissioner but working on a state but also a regional and a national but then into that federal national role and perspective, what changes about the way you look at issues and also how you interact with your colleagues

and stakeholders?

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COMMISSIONER CLYBURN: So I answer that in two or three quick ways. I always jokingly say that, you know, the only thing that's really different from how I approach it is the number of zeros. You know, you've got, you know, a couple of more zeros usually behind that.

But on a serious -- I really think -- I am really thankful for my sequence. I believe that being taught, you know, at the federal level gives me sensitivities -- excuse me -- at the state level gives me sensitivities at the federal level that I think if I did not have that sequence, I don't think I would be as effective and sensitive to -- I'm just -- this is not saying anything negative about anybody else, just sequence. I just really think that, you know, being able, before things changed back home in South Carolina, to have consumers call you directly and say, "My light is about to be cut off. Can you help me?" You know, something as basic as that really sensitizes you to the day-to-day plight of the people you serve. It's not

just the big corporations with, you know, a number of zeros. It is the people at home that have zero in their bank account that, you know, that want to keep their lights on. They're not trying to be, you know, irresponsible. They sometimes, you know, have situations that overwhelm them, and we have to serve them too.

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So, you know, from that perspective, I think the sensitivity was definitely a positive. And really when I give that example, I did it for more than one reason because I was hoping she was going to ask me something like that, because, again, people have a culture and sometimes having a recalibration of that culture brings about different results. So I really love the concept at the state level, and I would -- I think it would work -- continue to work at the federal level, having people from different backgrounds, particularly I think every commission should have a state perspective. I love what FERC and the FCC has done. I mean, almost kind of designating sort of a state. I think that's important to have that, you know, that point of view, you know, right there in the top tier.

So to not answer your question further, that, you know, I just really, you know, firmly believe that

this nation is better served when people are in your -you know, we talked about, you know, what states should be, you know, what their position should be. I've gotten a couple of colleagues a little -- but not too mad at me because I was right there with them, you know, for 11 years, and they understand that your point of view will change a bit, you know, your perception, you know, will change a bit, but I never -- I was heck bent on making sure that we changed the relationship when I was the chair of the Joint Board that the FCC had with NARUC. It was not pretty, and it really took almost the first year to kind of redefine, you know, our friendship, and I think that we did a pretty good job, you know, of doing that.

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And so, you know, those things help because this is truly a partnership. They're -- I'm not going to necessarily answer the calls that you get, and nor should I. You're here; you can answer them and address them more quickly. I might take a little bit of time, and by the time I get there, their phone has been off for a long time.

And so it's important for us to -- and even where we disagree. You know, we've got some issues with inmate calling. I'm going to try to forgive you for that. You know, we might, you know, have some issues on

Lifeline. I can kind of understand that one a little bit more. I might not agree with you, but I understand your perspective. It's important to be able to say, look, there is a goal that we're all trying to achieve. We may not see it through, you know, the same lens, but if we can move in the same direction to ensure that the consumers are best served, I think -- you know, we'll duke it out, but we'll duke it out in -- you know, moving in the positive direction.

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So I'm just very fortunate to have been able to, you know, be your colleague at the state level for 11 years and here for almost eight. And so I'm a senior citizen, you know, regulator in more ways than one. And -- but, again, you know, I'm incredibly grateful, and thank you for the question.

COMMISSIONER EDGAR: Well, Commissioner Clyburn, again, on behalf of my colleagues, always thank you for coming. It's wonderful to see you. It's always wonderful to see you. And Commissioner Clyburn is certainly one of those commissioners at the federal level who has stayed involved with NARUC and participating in committee activities.

Commissioner Brisé has already said this, but since I'm on my way out, I will reiterate it. Having served on the Joint Board many years ago --

COMMISSIONER CLYBURN: You know what the meetings look like.

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COMMISSIONER EDGAR: I do know what they look 3 like, and usually there aren't windows. But having 4 served on the Joint Board many years ago and had the 5 pleasure from the state side, we had at that point 6 7 Commissioner Copps and Commissioner Tate who were on the Joint Board, and both were very involved. And I think 8 9 it's okay to say this, both had generally very different views about where we should go and what we should do, 10 but their participation made that process so much more 11 valuable. 12 13 COMMISSIONER CLYBURN: Right. Right. 14 COMMISSIONER EDGAR: And so I thank you also on behalf of my colleagues for your participation in 15 16 that process --17 COMMISSIONER CLYBURN: Thank you. 18 **COMMISSIONER EDGAR:** -- because I really think good work can come from that. So thank you. 19 20 COMMISSIONER CLYBURN: Absolutely. 21 CHAIRMAN BROWN: Thank you. And, 22 Commissioner, I guess this will conclude our line of 23 questions, and I want to take the opportunity to thank 24 you again. 25 COMMISSIONER CLYBURN: My pleasure.

1	CHAIRMAN BROWN: And on behalf of the
2	Commission, I'd like to give you a plaque.
3	COMMISSIONER CLYBURN: Oh, my goodness.
4	CHAIRMAN BROWN: How many plaques do you have?
5	COMMISSIONER EDGAR: Not enough.
6	CHAIRMAN BROWN: You need another plaque.
7	COMMISSIONER CLYBURN: But this is my favorite
8	today.
9	(Laughter.)
10	CHAIRMAN BROWN: Thank you again for coming,
11	and we will continue our dialogue and discussions for
12	the remainder, later on. Thank you.
13	COMMISSIONER CLYBURN: Thank you.
14	CHAIRMAN BROWN: Thank you.
15	(Applause.)
16	Let's take a five-minute break. Take a
17	five-minute break. We'll reconvene in five minutes.
18	(Recess taken.)
19	CHAIRMAN BROWN: All right. This reconvenes
20	the Internal Affairs agenda. We are on Item 2, which is
21	the draft review of the 2016 telecom RAF report.
22	Mr. Long.
23	MR. LONG: In the interest of time, staff is
24	here to answer questions.
25	CHAIRMAN BROWN: Excellent.
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1	COMMISSIONER EDGAR: You've been here before.
2	(Laughter.)
3	CHAIRMAN BROWN: Commissioners, any questions?
4	It's a very brief report. Thank you for that. And if
5	there are no questions, can I get a motion, please?
6	COMMISSIONER BRISÉ: So move.
7	COMMISSIONER PATRONIS: Second.
8	CHAIRMAN BROWN: All those in favor, say aye.
9	(Vote taken.)
10	The motion passes unanimously.
11	Thank you, Mr. Long.
12	COMMISSIONER GRAHAM: Best report ever.
13	CHAIRMAN BROWN: Yeah.
14	Moving on to FEECA, Item 3.
15	MR. COSTON: Good morning, Commissioners.
16	CHAIRMAN BROWN: Good morning.
17	MR. COSTON: I'm here to present Item No. 3 to
18	you, which is this year's draft report, the annual
19	report on activities pursuant to the Florida Energy
20	Efficiency and Conservation Act. We'd like to ask to be
21	considered to adjust any scrivener's errors that we may
22	find during this process and would like to are now
23	available to answer any questions.
24	CHAIRMAN BROWN: Thank you.
25	Commissioners, any questions?
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Commissioner Patronis.

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COMMISSIONER PATRONIS: Is that a clip-on or did you tie that yourself?

MR. COSTON: I tied it myself. COMMISSIONER PATRONIS: That's impressive. CHAIRMAN BROWN: Respect.

COMMISSIONER BRISÉ: I know. Right?

CHAIRMAN BROWN: I do have a question on page 19 of the draft report. I think it's 19, and I could be wrong. It's somewhere in this report. Actually, I'm sorry, it's on page 31, and it talks about the solar, and specifically with the -- it talks about the company's solar for FPL, Duke, TECO, and Gulf. And I'm curious what percentage, with what we just approved in the rate case today, how much the total percentage of renewables are contained.

MR. MARGOLIS: Yeah. So right now, 3 percent of Florida's capacity is renewable. And right now, looking to the future, utilities have indicated that about 1,900 megawatts of renewables would come online over the next ten years.

CHAIRMAN BROWN: And of that 1,900, how much is solar?

MR. MARGOLIS: About 1,600.

CHAIRMAN BROWN: Okay.

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1	MR. MARGOLIS: And that does not include the
2	1,200 megawatts from the Florida Power & Light rate
3	case. So if you add the 1,200 megawatts from the
4	Florida Power & Light rate case, you would get to
5	3,100 additional megawatts over the next ten years,
6	which would bring renewable capacity in Florida to
7	4,900 megawatts. And we're looking at about
8	61,000 megawatts of total capacity, so that would be
9	approximately 7.9 percent of total capacity would be
10	renewable.
11	CHAIRMAN BROWN: Excellent. Thank you for
12	those numbers.
13	MR. MARGOLIS: Sure.
14	CHAIRMAN BROWN: Appreciate it.
15	Commissioners, any other questions or
16	comments?
17	COMMISSIONER GRAHAM: 7.9 percent when?
18	MR. MARGOLIS: Within ten years.
19	COMMISSIONER GRAHAM: Okay.
20	CHAIRMAN BROWN: Yeah, sure. Commissioner
21	Edgar.
22	COMMISSIONER EDGAR: Thank you.
23	Two real quick. And just a follow-up from the
24	discussion that we had recently, I believe that, and I'm
25	not sure where it is in here, but that you said that
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within the next time -- ten-year time period or time window that our renewable portion of our fuel portfolio, that for the first time the majority of that renewable piece will be from solar.

MR. MARGOLIS: Yes.

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COMMISSIONER EDGAR: Is that correct? And when is that expected with the plans that are kind of in the pipeline?

MR. MARGOLIS: Yeah. So before the FPL rate case it was going to be 1,900, and 1,600 of the 1,900 would be solar. So that's almost 80 percent. Then now we're adding another 1,200. So now we're looking at 3,100 megawatts of newer renewables potentially over the next ten years, and 2,800 of those from solar. So 90 percent of new renewables would be solar because that's what's most appropriate for Florida's geography, given the advantages.

18 COMMISSIONER EDGAR: I would point out, as I 19 know we're all aware, that during the time I've been 20 here and we've looked at that renewable portion of our 21 greater fuel portfolio, that biomass has generally, 22 biomass and municipal solid waste have generally been 23 the largest piece of that renewable slice. And the progress that is being made and is continuing to be made 24 25 with solar I think is worth noting.

And then we talked about this, and I just wondered if you had the opportunity to follow up, that Gulf is working on a pilot project for time-of-use rates, and I know we discussed that a little bit. Do you have any additional information about when that might go into place or --

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MR. MARGOLIS: Yeah. So Gulf has already introduced a residential Time-Of-Use pilot program so that customers can use energy better times of the day that are lower cost. And right now they already have 330 customers. They're doing a pilot. The goal is to have 400 customers. And they're using Wi-Fi-enabled thermostats to enable different pricing electricity at different times of the day. You could get a lower price for electricity if you do laundry at 11 p.m. as opposed to 6:00 p.m.

COMMISSIONER EDGAR: That's when I do it. COMMISSIONER PATRONIS: That's when I do it. COMMISSIONER EDGAR: Between 11:00 and 2:00 a.m., seriously.

COMMISSIONER PATRONIS: Oh, yeah.

COMMISSIONER EDGAR: Once the kids have gone to sleep, that's when I'm doing laundry and running the dishwasher. So I'm all for those time-of-use rates. Thank you very much for the follow-up.

CHAIRMAN BROWN: Thank you, Commissioners.

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Two more I forgot -- I'm curious about. Florida Power & Light also was -- launched a research program about smart thermostats and actually found electric savings. I think it's a very interesting program. I'd be curious to see more detail on that over the next few months, more information about that. And I know Duke, as well as TECO, have pilot programs or they're studying different renewable energy system pilot programs and studying thermal energy storage. Duke has the SEEDS project. Those are very exciting and interesting. And just if we could get some more details over that -- over the next few months.

And then getting back to the community solar programs, we approved a solar program, a voluntary solar program for FPL, the SolarNow. And you see some -- in this report it shows other similar programs. I am just curious about where, at least specifically for SolarNow, what the subscribership is and how that is faring. Do we have any information on that?

MR. COSTON: We do not have that readily at hand. According to that program, they are going to report back that information at the end of the three-year cycle. But we can certainly work to gain and get a status update on that.

000050 CHAIRMAN BROWN: Absolutely. I'd be curious 1 to see how those voluntary programs are really faring. 2 Commissioners? Commissioner Brisé. 3 COMMISSIONER BRISÉ: Thank you. So I just 4 want to highlight some of the outreach work that has 5 been done by the Commission here. We started looking 6 7 for -- from our Google Analytics, about 677,000 people have reached out to our website to see how they can be 8 9 served by the Commission, and I think that's an important fact. You know, very often we go places and 10 people don't know what in the world we do. 11 12 CHAIRMAN BROWN: Uh-huh. COMMISSIONER BRISE: But then you open up the 13 14 conversation a little bit, "Oh, yeah, I've been to your 15 website," and so forth. And then the other thing is that, you know, we 16 17 have, either by mail or by phone, answered requests for 300 -- I mean, 35,000-plus brochures going out to the 18 public. So I want to thank our PIO office for their 19 hard work and actually going out to these senior 20 21 communities to provide information. So I think that's 22 work that is commended. And thank you, Madam Chairman, 23 for being out there on our behalf. 24 CHAIRMAN BROWN: They're great. No, they are

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great, and they come up with great ideas all the time to

further educate people. We have a great PIO office. Thank you for highlighting that, Commissioner Brisé. Can I get a motion to approve this with the ability of staff to make any scrivener's errors? COMMISSIONER PATRONIS: So move. COMMISSIONER GRAHAM: Second. CHAIRMAN BROWN: All those in favor. (Vote taken.) All right. The motion passes unanimously. Thank you, gentlemen. Moving on to Item 4, which is the Lifeline. MR. FOGLEMAN: Good morning, Commissioners. Greg Fogleman for Commission staff. Item 4 is the draft 2016 Lifeline Report. This report is due to the governor and the legislature by the end of the year. In this year's report, we note that Lifeline subscribership increased by 2 percent over last year. Low income disbursements in Florida for the reporting period was approximately 92 million. This suggests that consumer outreach and enrollment process in Florida is having a positive effect. Staff is requesting editorial privileges to make any corrections and update any data as needed. Staff is available for your questions. CHAIRMAN BROWN: Thank you. Thank you so much

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for your work on this.

Commissioners, questions?

I'm curious -- I have a question about the FCC's changes and the eligibility criteria. Do you foresee them having an even more positive impact on enrollment?

MR. FOGLEMAN: I think for Florida, I mean, SNAP is primarily the largest program that we sign consumers up for the Lifeline, so that's staying intact. So that's a positive.

As far as the addition of the pension benefit, I think that's -- that has the potential to be very positive, but we just don't know until it starts up and time will tell.

> CHAIRMAN BROWN: And when will that be? MR. FOGLEMAN: December 2nd.

CHAIRMAN BROWN: Okay. Thank you. Are there additional outreach efforts being organized regarding the changes to the Lifeline program? Anything specific?

MR. FOGLEMAN: I believe we're working on frequently asked questions and PR information, and we're also working with the carriers to make sure everybody is on board and knows about the changes, as well as USAC is doing a lot of stuff to get on board.

CHAIRMAN BROWN: Excellent. Thank you.

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Commissioners, any other questions?

COMMISSIONER BRISÉ: No questions. Just a comment.

CHAIRMAN BROWN: Please.

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COMMISSIONER BRISÉ: On this note, I think Florida has been a leader, and as we look across the nation as they're trying to finalize the eligibility database, Florida is looked at as one of the model states to follow. So I think kudos to our state for the hard work that has gone into putting -- I think you were chair when that happened.

COMMISSIONER EDGAR: I was. Thank you for that shout out.

COMMISSIONER BRISÉ: So, you know, across the nation, USAC is trying to identify states that are positioned to follow our model, and I think our results show that it has worked well.

CHAIRMAN BROWN: Excellent.

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 Can I get a motion with -- to approve with

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 editorial rights?

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 COMMISSIONER BRISÉ: So moved.

COMMISSIONER GRAHAM: Second. **CHAIRMAN BROWN:** All those in favor. (Vote taken.)

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Motion passes unanimously. Thank you.

000054 And on to our last report, which is the 1 Ten-Year Site Plan. 2 3 COMMISSIONER PATRONIS: Go 'Noles. CHAIRMAN BROWN: I understand that you lost a 4 5 bet. MS. MTENGA: I did. 6 7 CHAIRMAN BROWN: Sorry to hear that. MS. MTENGA: So, yes. Go Gators! 8 9 CHAIRMAN BROWN: Yay. MS. MTENGA: Is this on? 10 11 (Laughter.) 12 CHAIRMAN BROWN: He's going to tweet that out. MS. MTENGA: Okay. Good morning, 13 14 Commissioners, and go Gators! Item No. 5 is a draft review of the 2016 15 Ten-Year Site Plan of Florida electric utilities. 16 The 17 review is similar in format and content to last year's 18 review. In September a public workshop was held. FRCC 19 provided comments on its load and resource plan and fuel 20 reliability for the FRCC region. 21 Florida's four IOUs -- FPL, Duke, TECO, and 22 Gulf -- showcased an overview of their planning process 23 and various aspects of their plans. All comments were 24 also received by SACE and Sierra Club. At this time, 25 staff seeks the Commission's approval of the draft

review of the 2016 Ten-Year Site Plans which would find each utility's plans suitable for planning purposes. If the Commission approves the draft, the review and attached comments would be provided to the Department of Environmental Protection for consideration in future proceedings. Staff is available for any questions.

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CHAIRMAN BROWN: Thank you.

Commissioners?

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I have some questions.

MS. MTENGA: Go ahead.

CHAIRMAN BROWN: On page 16 of the draft report regarding electric vehicles, it's an area of much interest that I personally have. What resources are in place to adjust the new sources of energy consumption such as electric vehicles, and what's needed to address the increased consumption?

MR. ELLIS: In this instance, it is very similar in some ways to the rollout of AC and air conditioning in Florida in terms of the uptake of demand. However, with potential future demand-side management programs and things like that, we think that can be used eventually to address the peak concerns to prevent on-peak charging of electric vehicles or at least disincentivizing on-peak charging. That would allow some of the existing generation assets and things

000056 like that. While more energy would have to be produced, 1 it would not necessarily require much additional 2 3 generation. However, we are still looking into that as a concern for each of the electric utilities. At this 4 point in time, the number of vehicles we're normally 5 looking at, at least in the ten-year period that we were 6 7 provided, approximately a third of a million out of, I believe, 20 million total vehicles in the state. 8 9 CHAIRMAN BROWN: Say that again. MR. ELLIS: About a third of a million out of 10 20 million in the state, I believe. 11 12 CHAIRMAN BROWN: And that number is only going 13 to be growing. 14 MR. ELLIS: Yes. 15 CHAIRMAN BROWN: Do we know what the rate of 16 growth is? 17 MS. MTENGA: I don't think there's much available from the board of motor vehicles as far as the 18 19 amount of growth is concerned. They're not -- right now 20 they're not keeping as robust of a record as we probably 21 have a chance to get in the future as we implement 22 different programs for that. 23 CHAIRMAN BROWN: Okay. You know, one thing I'd like -- I mean, I personally would love to see 24 25 in the next year's Ten-Year Site Plan is tracking the

battery storage, R&D projects, the pilot programs. I think those are very exciting, innovative aspects that we should definitely look into and at least provide information so that we get the whole picture of what the utilities are doing in their site plans.

> Commissioners, any other questions? Commissioner Edgar.

COMMISSIONER EDGAR: Thank you. No questions, but would just -- thank you very much -- build on your comments about, you know, the potential future electrification of the economy, and I do think that that's something that we all and everybody has a great interest in and has the potential to certainly impact the industry, and certainly in a state such as ours, a large state, a growth state, a progressive technological state, and an entrepreneurial state, et cetera. So I really think that your interest in that is key. And I do think that it is broader than just the transportation sector as well, so I'll be interested in additional information about that over the next time. You know, even appliances are possibly becoming more multi-purposed and, therefore, using more energy as they do more things and are used more during the course of a day.

And I did want to ask you, and this is just

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000058 such a little bit of this, but did you have the 1 opportunity to update the COL information? 2 3 MR. ELLIS: We -- actually that and a few other minor --4 COMMISSIONER EDGAR: Minor things that we'll 5 do in the -- just some of the discussion that we had 6 7 about some things, very minor, in the briefing that had maybe a few changes that had come since the draft was 8 9 issued and to make it as current as possible. MR. ELLIS: If we could be granted authority 10 to make a few minor modifications to reflect those, that 11 12 would definitely be appreciated by staff. CHAIRMAN BROWN: Okay. Do we have a motion at 13 14 this time? If there are no other further comments or questions --15 COMMISSIONER EDGAR: I move approval with the 16 17 ability for staff to make whatever technical adjustments 18 appropriate. 19 COMMISSIONER PATRONIS: Second. CHAIRMAN BROWN: Any further discussion? All 20 21 those in favor, say aye. 22 (Vote taken.) 23 Thank you. It passes. 24 Thank you all for your work on this, and 25 meetings. FLORIDA PUBLIC SERVICE COMMISSION
All right. We are now on to the General Counsel's report. That's you, Keith.

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MR. HETRICK: Yes. Thank you, Madam Chair. Fifteen seconds.

All is well in General Counsel's world. We're on to the next rate case, the Gulf rate case. We're also reviewing lessons learned from the FPL case to implement hopefully an even more efficient hearing process in the future starting in 2017. We've got another big water case on the horizon, as you all know.

We recently hired a new research -- or actually a new deputy clerk position which we've been sorely in need of. And we're so excited about that because we went through three rounds of interviews and we really found someone who's out of sight who will work with Keino's shop.

CHAIRMAN BROWN: Is that person here?

MR. HETRICK: That person is not here. She will start officially December 2nd, I think. Monday, this Monday. We will introduce her to the Commission soon.

CHAIRMAN BROWN: Great.

MR. HETRICK: She'll work with Ashley. Her name is Sandra -- is it Jones?

MR. YOUNG: Yes.

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MR. HETRICK: Sandra Jones.

And we're preparing for the legislative session, which is on the horizon, and we know that's of interest to you, Madam Chair, and all the Commissioners here. We want to be very proactive and reach out to the legislature and provide a lot of support. And I think Mark Futrell and Braulio's staff are going to be working real closely together on that. That's my report.

CHAIRMAN BROWN: Excellent. Thank you. And I know a lot of work is already in the midst for staff, so I want to thank you guys for being on top of it this session.

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Executive Director's report.

MR. BAEZ: Thanks, Madam Chairman.

A couple of items. We didn't have Internal Affairs in October, so there's a couple of things.

First, I want to join you in recognizing the staff. Your vote earlier today, we brought to a close the FPL rate case. It was the signature case that we had this year. And as you mentioned, that involved a lot of hours on the part of all the staff. It was all hands on deck at the Commission. So I personally am very proud of the work that we did and want to commend the entire -- all the efforts of the staff as well, General Counsel and the technical staff and the

administrative staff as well. We even had to stare down a hurricane to do it, both metaphorical and literal, as well.

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On Hurricane Matthew, the actual hurricane, I wanted also to recognize staff. As you well know, as many of you have had the opportunity to visit the EOC, whether it's in stand-down mode or actually fired up for action, some of our staff staffs ESF 12 when they're in DEFCON mode, you know, when there's an active storm or emergency going on. And the folks that do that do a wonderful job of doing their specific -- working their specific magic, and I just wanted to give them a shout out as well. First and foremost, Rick Moses, who does a wonderful job keeping folks calm over there and really coordinating the efforts of all of our utilities in terms of restoration and outage support; Robert Graves; Phil Ellis, who was here earlier; Penny Buys; and Adam Hill, to mention just a few.

There was -- Keith mentioned the Gulf rate case earlier, and I wanted to focus you all on that. Also in October we took a really significant step forward, and you've heard me mention this in the abstract over my time here, the notion of this Commission becoming online, becoming paperless, and we took a very significant step forward in terms of

electronic filing in October. We had our first e-filed MFRs. Gulf was our first.

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And I wanted to throw out some numbers for you so you can see what the reality of these things are. And I'll use two examples to hold up, if you'll indulge me for a moment, this recent FPL rate case and the Utilities, Inc. filing, for scale.

Okay. So the Utilities, Inc. filing is about the size of the Gulf filing in terms of paper and documents. But the FPL filing, so that you can see the time that it takes, FPL had 38 documents filed paper-wise. Now they were a total -- it was a paper filing. Right? Just in terms of time, it was 5,000 pages that were filed, 5,400 roughly. It took 33 hours of our clerk, our clerk division staff to process, 33 hours' worth.

UIF, by comparison, had 26 total documents filed, roughly 3,000 pages filed, 14 hours of staff time. Keep that -- hold that in mind.

By comparison, the Gulf filing had 29 total documents filed, 3,500 pages filed. It took two and a half hours, two and a half hours of clerk time. You can see the step that we've taken. And I'm over the moon about it because we've actually, you know, delivered on this potential that we've been wanting to harness for so

long. And I think that the --

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CHAIRMAN BROWN: Uh-huh. Five years, six years.

MR. BAEZ: Yeah, it only took five years. CHAIRMAN BROWN: It only took five.

MR. BAEZ: Overnight -- a five-year overnight success.

(Laughter.)

But despite all the time that it's taken, you know, it's at our doorstep, and I think we should all be very excited about it, and the upside is still there. We've got a couple of possible next steps that we're working with our colleagues in the General Counsel's office on rule changes that may be necessary in order to be able to accommodate the filing of confidential filings. That may take some rule changes, that may take -- and also changing rules to eliminate the number of paper copies required, things of that nature, to be able to smooth the process a little over. But I just wanted to let you all know, you know, as to the kind of economies that we're being able to gain by taking this important step forward, and hopefully it gets better from there.

CHAIRMAN BROWN: Commissioner Graham has a question.

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MR. BAEZ: Yes.

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COMMISSIONER GRAHAM: Do we know what the impact was for the utilities as far as them putting all that stuff together and getting it to us?

MR. BAEZ: I probably can't speak to that. I don't know if -- I don't know if anybody from Gulf is willing to own up to what it is. I do have the timing. It took them 30 minutes to file and they filed after 5:00, if that, you know, if that's useful information.

COMMISSIONER GRAHAM: It could just be curiosity, you know, I mean, because those are very good numbers you have and those are, you know, things you can picture and see, you know, what the impact was. It would be nice to see from their point of view, you know, what the impact really was.

MR. BAEZ: The feedback was generally positive. If it hadn't been, believe me, we would have heard it. I kind of tend to -- you know, you kind of back up until you hit something, and so I know that the utilities -- certainly in a large respect they are our customers in a sense, they come and they do business at the Commission in that respect. They're very hands-on with our processes, as I'm sure you know. And certainly how they interact with the Clerk's office in particular because they've got to get their stuff in on time;

otherwise, it doesn't count. So with the Clerk's office in particular, they're very vocal and very hands-on about how they interact with it. This being -- and certainly an MFR filing, a rate case filing is kind of top of the list. Right?

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COMMISSIONER GRAHAM: Well, the reason why I asked, because everything new is --

MR. BAEZ: Yeah.

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COMMISSIONER GRAHAM: -- it takes effort from everybody, and it would be nice to learn from what they went through so when the next one comes through, we can kind of give them a heads-up on what happened.

MR. BAEZ: This was -- the fact that Gulf was first is not necessarily -- they weren't the only ones that were involved, clearly, in the discussion.

COMMISSIONER GRAHAM: Uh-huh. Okay.

MR. BAEZ: I guess if that means anything. You know, certainly all the utilities, all the -- all our regulated utilities have had input into our, you know, how we have modified our systems and the access to our systems in order to carry this out. They just happened to fall on the -- at the time when we were ready to go. They were -- I would call them the lucky ones, but they may have a different opinion. I've heard nothing but positive things.

000066 CHAIRMAN BROWN: Thank you. Are you --1 MR. BAEZ: Yes, I'm all done. 2 3 CHAIRMAN BROWN: I have a question for you. Do you have -- are you willing to throw out the 4 5 tentative dates scheduled for next year for the hurricane technical workshop? 6 7 MR. BAEZ: The --CHAIRMAN BROWN: I thought it was in March, 8 9 but --10 MR. BAEZ: I may punt to Mark. You're 11 probably right, probably the end of first quarter, but I 12 don't want to --13 MR. FUTRELL: That sounds about right. 14 MR. BAEZ: Either end of March or early April is what we're looking at, because we've got a couple of 15 16 other workshops that are --17 CHAIRMAN BROWN: Apparently a lot. 18 MR. BAEZ: I say a couple. It could be, you 19 know, it could be up to three if we can't link up a 20 couple of them. But they're all vying for that precious late first quarter spot. So how they fall in order 21 22 date-wise --23 CHAIRMAN BROWN: Yeah. Let's get that locked 24 down so we can give as much notice. 25 MR. BAEZ: We're working very hard to try and FLORIDA PUBLIC SERVICE COMMISSION

lock it down.

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CHAIRMAN BROWN: Mark, any --

MR. FUTRELL: No. I was just going to say
we're also contemplating having another --

CHAIRMAN BROWN: Round table.

MR. FUTRELL: -- Internal Affairs meeting to bring folks in to talk about storm preparation as well before you.

CHAIRMAN BROWN: Thank you for that. Thank you. I appreciate it.

Keith.

MR. HETRICK: Madam Chair, I overlooked one thing. In response to, I guess, Commissioner Brisé at the last Agenda Conference, coming out of that, I think we had the Aquarina case and some issues with customer -- how they report complaints and what's a complaint. We are actively, right now pursuing an active revision of that specific rule to make it easy and seamless for customers to register complaints and make it clear that concerns, complaints all will be recorded. We're putting -- making sure that our responsibilities placed on utilities are clear. But that will be brought before you. We're not waiting on any sort of massive rule revision. But that's very important that the burden be on the utility, and the

000068 customers can easily file complaints and that we have a 1 record of all customer complaints, which will help out, 2 I think, in all water cases. 3 CHAIRMAN BROWN: Any comments? 4 COMMISSIONER BRISÉ: No. 5 Thank you. MR. BAEZ: And one last item. The next 6 7 Internal Affairs will be Thursday, January 19th, 9:30 8 a.m. 9 CHAIRMAN BROWN: Okay. Thank you. That doesn't mean we have stuff -- we have other meetings 10 prior to that, but that's the IA. 11 MR. BAEZ: Oh, yes. It's the next IA. 12 13 CHAIRMAN BROWN: Thank you. 14 Okay. On to other matters. Commissioners? 15 First and foremost, I have to wish a happy 16 17 birthday to my girl, Katherine Fleming. It's her birthday today. She doesn't like to celebrate. 18 19 (Applause.) She's just the best. She's like a sister 20 21 to me. So I just wanted to share that all with you. 22 Also, Commissioners, we've had a lot of 23 different conferences over this past month that 24 folks have attended. Three of us were unable to attend the NARUC, and I didn't know if there were 25 FLORIDA PUBLIC SERVICE COMMISSION

any highlights that you wanted to point out or 1 recognize for us. I know Commissioner Brisé had two 2 3 resolutions that were passed and approved by the board. Anything you want to share with the folks? 4 COMMISSIONER BRISÉ: Sure, I quess. So we did 5 one resolution that is particularly germane to us --6 7 CHAIRMAN BROWN: Yes. Thank you. **COMMISSIONER BRISÉ:** -- and that resolution 8 9 was recognizing the efforts of our fantastic 10 Commissioner who served as president of NARUC, Commissioner Lisa Edgar. And so the board unanimously 11 approved the resolution recognizing her efforts and her 12 13 work, not only as a Florida Commissioner but her work on the national stage as our Commissioner, so. 14 15 (Applause.) CHAIRMAN BROWN: Hey, that's great. 16 Thank 17 you. COMMISSIONER BRISE: And I know that we will 18 19 roast her at a later time, so just for the record. 20 CHAIRMAN BROWN: Yes. 21 COMMISSIONER EDGAR: Thank you, Commissioner 22 Brisé, for your sponsorship of that. Much appreciated. 23 I appreciate your friendship. 24 CHAIRMAN BROWN: All right. Last we have 25 to -- we are recognizing our employee of the month,

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Mr. Justin Burton.

COMMISSIONER EDGAR: Yay.

CHAIRMAN BROWN: Justin has been the "Employee of the Month," and he was hired by the Commission in March of 2008 in CAO. He moved to HR in 2014 and became the PSC personnel officer in October 2015. He just loves helping all of staff with their HR needs. I know a lot of us have probably interacted with him. Especially as chair, you really always have to be on top of that. So I wanted to recognize him for his service, and we will be giving him his award later. But if there are no other matters, this will conclude the Commission Internal Affairs Conference. It's adjourned. (Internal Affairs adjourned at 11:57 p.m.)

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2	COUNTY OF LEON)
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4	I, LINDA BOLES, CRR, RPR, Official Commission
5	Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein
6	IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.
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10	I FURTHER CERTIFY that I am not a relative, employee, attorney, or counsel of any of the parties,
11	nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I
12	financially interested in the action.
13	DATED THIS 6th day of December, 2016.
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16	Jinda Boles
17	LÍNDA BOLES, CRR, RPR Official FPSC Hearings Reporter
18	Office of Commission Clerk (850)413-6734
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